Prudhoe Bay West End Gas Lift Supply Optimization

By

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Abstract

The western extension of Alaska's Prudhoe Bay, known collectively as Eileen West End (EWE), operates under a gas lift pressure supply constraint. This constraint is largely contributed by two factors: the extensively long gas lift supply line that stretches across the western field and the large number of production wells offtaking gas lift to stay online or enhance production. The gas lift supply line is approximately 18.5 miles long and provides gas lift to 200+ production wells. This results in a pressure drop severe enough to start hindering production on the western most side of the field as low gas lift supply pressure can cause unstable production, reduced production rate, or stop production altogether. Theory suggests that boosting the system's gas lift supply pressure will improve production from the field.

In order to quantify the benefit of boosting the gas lift supply pressure and determine the most optimal way to do so, an industry proven physics based multiphase flow simulator was used to construct two models, a production system and a gas lift system. This dual integrated model approach enabled the ability to capture and predict production effects caused by changes in gas lift supply pressure and determine if boosting the pressure will be beneficial from an operator standpoint.

The objective of this project is to describe how building an integrated production model can capture and quantify changes in production for a very large and complex interconnected system. Applying these types of models can help steer important operational and economic decisions to minimize risk and expense as an operator. Using the models, several scenarios were evaluated to determine and quantify the most optimal approach to address the low gas lift supply in EWE. It was determined that shutting in the least competitive wells to boost the gas lift supply pressure was the best scenario to implement for several reasons: the scenario still yielded a high production benefit, it did not have any investment requirement, and the actions could be reversed if a negative impact was realized.

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1.0 Introduction

Alaska's North Slope is home to one of the largest oil fields in North America – Prudhoe Bay. Discovered in 1968, the Prudhoe Bay field is a massive and complex sandstone reservoir covering more than 200 square miles. The main reservoir contains a large oil rim which consisted of more than 20 billion stock tank barrels (STB) of hydrocarbon liquids and approximately 46 trillion standard cubic feet (TScf) of free and associated gas originally in place (Szabo and Meyers., 1993).

The Prudhoe Bay field has a western extension called Eileen West End; also abbreviated as EWE (see Figure 1). EWE's infrastructure consists of five well pads that produce and flow into a single large diameter flowline (LDF) that then carries the produced fluids back to Prudhoe's production facility, Facility 2*. The well pads are A1*, A2*, A3* A4* and A5*; collectively known as "West End".

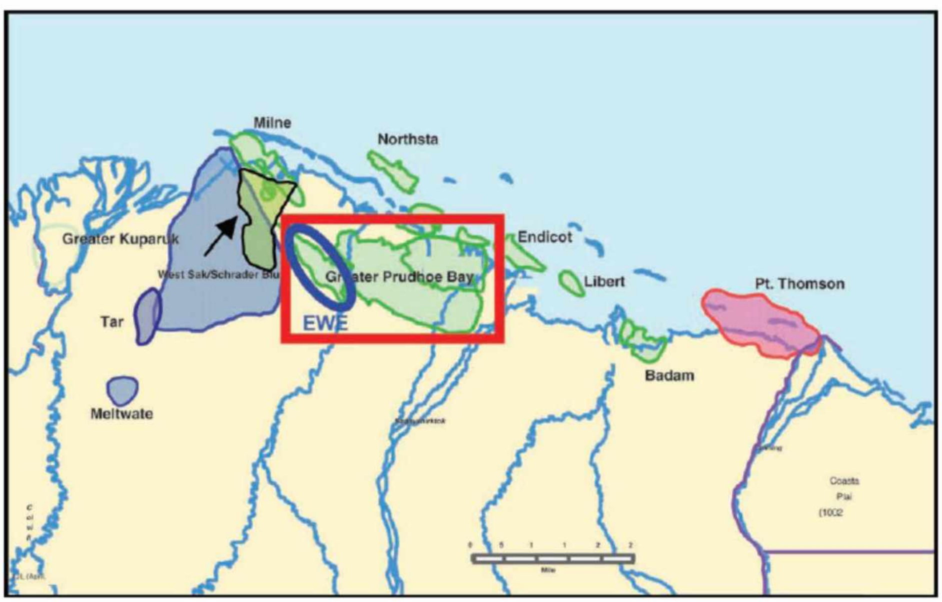


Figure 1 - Location map of Prudhoe Bay and EWE, Alaska North Slope. (Panda et. al., 2009)

Due to the continuous development of the West End, fluid production from the area eventually reached several constraints. The first production constraint was realized when the EWE LDF reached its capacity due to a velocity limitation. A mixture velocity limitation of 70 ft/s is imposed on the LDF to prevent corrosion inhibitor chemical from stripping off the interior surface of the pipe. This meant that even though the available wellstock from EWE was competitive to flow from a Total Gas-to-Oil Ratio (TGOR) perspective compared to other wells producing to Facility 2 (FAC2*), several wells have to stay shut-in to comply with the velocity limit on any given day.

The second production constraint is realized from the lack of gas lift supply pressure due to the long supply line having an extensive pressure drop and too many wells needing gas lift to flow. The gas lift supply line is an approximate 97,500 ft or 18.5 miles in length; from FAC2* to well pad A5* (see Figure 2). This line supplies a total of 19 well pads and its line diameter reduces along its length; starting with an internal pipe diameter (ID) of just over 10 inches that tapers down to just under 8 inches ID towards the end. The supply pressure and flow rate originate from turbine compressors that are located at Facility 1 (FAC1*), further east of FAC2*. These compressors supply gas lift to not only the EWE wells, but the majority of the wells in the West Operating Area (WOA). The extensive amount of wells needing gas lift to flow in the WOA further reduces the gas lift pressure available to the West End. This causes a disadvantage and can actually reduce overall oil production if more gas lifted wells are brought online.

The low gas lift supply pressure won't allow for a high enough casing pressure for gas

Figure 2: WOA Gas Lift Supply Line. Retrieved from BP America – OneMap Tool.

lifted wells to lift from their lowermost orifice gas lift valve (OGLV). This condition can cause unstable flow, multi-pointing, reduction in production rate, and even stop production all together. This phenomenon is especially prudent as the supply line ventures westward; with the source pressure starting at ~2,100 psi and then dropping all the way down to ~1,630 psi towards the end of the line at well pad A5*.

This counterintuitive scenario called the need for a physics-based hydraulic network model to capture and predict the production effects caused by low gas lift supply pressures due to compressor outputs and/or the number of wells offtaking gas lift. The tool also needed optimization capabilities due to the large number of high value wells competing for the limited amount of gas lift pressure and LDF space. The model also had to incorporate a way to test different development scenarios the Operator could potentially invest in to boost the gas lift supply pressure and quantify the benefit.

I found the best approach was to use an industry proven, commercially available, multiphase flow simulator, PETEX GAP, in conjunction with a hydraulic nodal analysis simulator, PETEX PROSPER, to build both the production and gas lift injection systems that closely mimic the real infrastructure of the West End part of the field.

Four main scenarios were built and evaluated: 1) A base case to match the model to real production numbers 2) Adding an extra compressor before wellpad A3* to boost supply pressure 3) Adding an extra compressor before wellpads A4* & A5* to boost the supply pressure 4) Shutting in lower marginal gas lift wells to reduce the number of gas lift offtake. The objective of this project was to compare the four scenarios to determine which approach would yield the most benefit from both an operational and production standpoint.

2.0 Gas Lift

To understand gas lift optimization, we must first understand the principles of gas lift and how it is used. Gas lift is a method of artificial lift that uses high-pressure gas from an external source to supplement formation gas to lift well fluids. The purpose of gas lift is to reduce the density of the fluids in the tubing by injecting gas into it. The bubbles formed by the gas essentially help lift the liquids. This ultimately acts to lower the flowing bottom-hole pressure at the bottom of the well since the density of the hydrostatic column is reduced. The lower hydrostatic head, creates a pressure differential that allows the fluid to flow into the wellbore and up to the surface (see Figure 3).

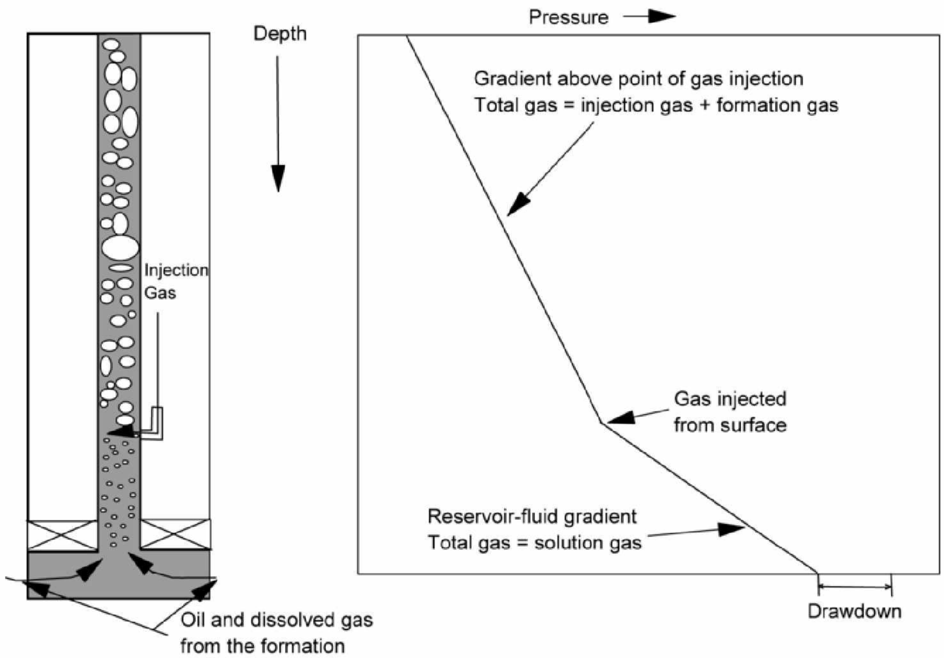


Figure 3: Generic gas lift well schematic and flowing pressure gradient. Adapted from Petrowiki, by Kkornegay, 2013, Retrieved from https://petrowiki.org/File:Vol4_Page_522_Image_0001.png.

The vast majority of the gas lifted wells are produced by continuous flow, which is when a continuous flow of gas is injected into the production tubing at a maximum depth that depends on the injection gas pressure and well depth.

Gas lift is typically used on wells that cannot flow naturally; meaning that the pressure from the surface, hydrostatic column, and frictional pressure loss from the tubing all overcome the reservoir pressure from below. Wells that have been shut-in for a period of time might only need a slight “kick-off” of gas lift to unload the hydrostatic head that inflowed and built up in the wellbore while the well was offline. Gas lift is also used to increase production in flowing wells by increasing the drawdown.

There are several advantages and disadvantages to using gas lift as an artificial lift method. One of the advantages to gas lift allows it to work with reservoir gas at any GOR (Gas-Oil-Ratio). Several other advantages include: it doesn’t need electrical power, it can be adjusted relative to changing well behavior, it can be used with wells that produce solids, it doesn’t cause restrictions in the tubing, it can be used with deviated wells, it is relatively low cost, and it requires only relatively simple intervention work if needed.

However, gas lift has several disadvantages: it must have a continuous high pressure gas source, it has a low efficiency compared to other lift methods, it doesn't work on low pressure wells, it can induce slug flow, it doesn't work well with low API (viscous or heavy) oils, and it is prone to cause well integrity issues such as TxIA (Tubing by Inner Annulus) communication, and may induce asphaltene precipitation.

Despite the disadvantages, gas lift is one of the more forgiving forms of artificial lift since even poorly designed installations can still lift some fluids. The individual well designs play a key role on how efficient and productive gas lift can be.

2.1 Gas Lift Design

The injected gas is supplied in a closed loop system; it is normally collected from separators and then compressed, dried and supplied to the well. If formation gas is unavailable, then an outside source of gas can be used. The lift gas is normally injected down the inner annulus of a well and into the tubing through gas lift valves (GLV) (see Figure 4).

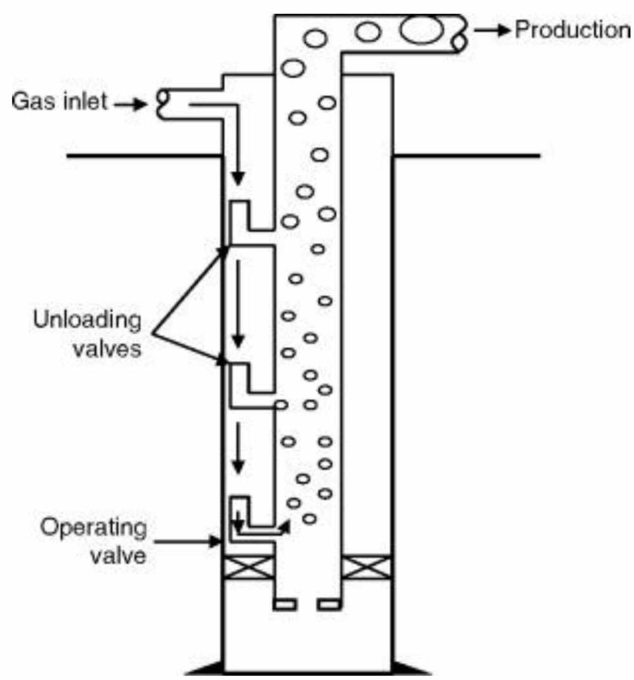


Figure 4: Gas lifted wellbore schematic with unloading valves. Adapted from Science Direct, by B.Guo, 2007, Retrieved from https://www.sciencedirect.com/topics/earth-and-planetary-sciences/gas-injection.

The valves are spaced throughout the tubing at designed intervals and close in sequence as the gas-fluid interface is pushed down the inner annulus due to the unloading process. The valves are set in mandrels, which are part of the tubing completion design (see Figure 5). The GLVs are typically simple single-element type, unbalanced valves with nitrogen-charged bellows (see Figure 6).

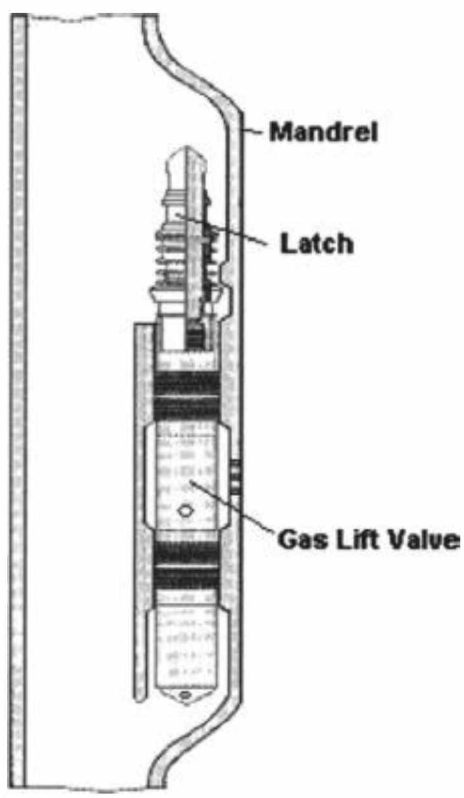


Figure 5: Cross section of a gas lift mandrel. Retrieved from BP America – Gas lift overview presentation.

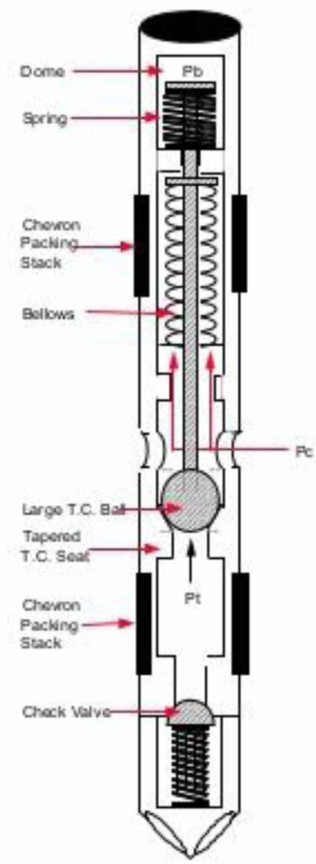


Figure 6: Cross section of a gas lift valve. Retrieved from BP America – Gas lift overview presentation.

The valve will automatically open under a specific pressure. The opening function is operated by a bellows that is a gas or spring loaded mechanism. The top most chamber is filled with a pressurized gas to a specific pressure and then sealed. The bellows is forced up against its seat due to the internal pressure. The difference in pressure in the well's inner annulus will open the valve so that the gas is injected into the fluid in the tubing. The gas will enter the tubing from the upper most valve first. The pressures in the annulus and tubing are approximately equal the instant a gas lift valve is uncovered. As soon as gas begins to enter the tubing through the next lower gas lift valve, the annulus pressure will begin to decrease because the newly uncovered gas lift valve is set to remain open at a lower pressure than the unloading valve above. As less and less gas enters the tubing through the upper unloading valve, the gas rate through the lower valve increases until the annulus pressure decreases to the closing pressure of the upper unloading valve. The unloading sequence is completed once all the injection gas is entering the tubing through the lower most orifice valve and all upper valves are closed.

There are several important variables that affect the design and operation of a gas lifted well: bottom-hole pressure, bottom-hole temperature, wellhead flowing pressure, gas supply pressure, gas injection rate, tubing diameter, casing diameter, well production rate, well productivity index, watercut, oil gravity, water gravity, injection gas gravity, and formation oil-gas ratio (Pittman., 1982). Other variables may also affect the efficiency of the gas lift design such as: friction factor, wellbore deviation, flow regime, etc.

2.2 Gas Lift Surface System

For gas lift to be effective, a reliable, adequate, and continuous supply of good quality high-pressure lift gas is mandatory. The source of the gas lift is typically from treated and compressed formation gas, entailing that the producing reservoir or area must have adequate gas production to supply the lift gas. This sequence can be seen in Figure 7 where gas is produced from the reservoir and then separated from the fluids to be treated and compressed into gas lift gas. If the production of gas declines or is unavailable, an outside source of gas will need to be acquired by importing gas from a different region or creating nitrogen using a nitrogen membrane unit as a gas source.

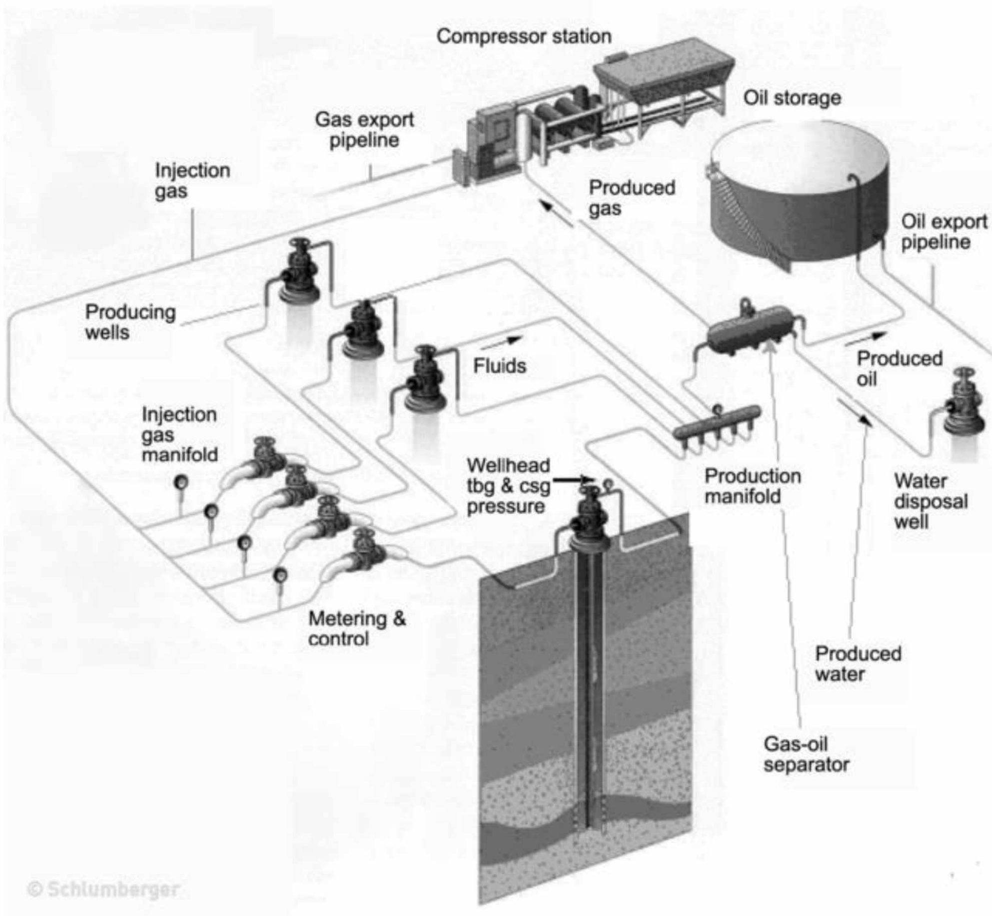


Figure 7: Schematic of a gas lift system surface infrastructure. Adapted from Petrowiki, by Kkornegay, 2013, Retrieved from https://petrowiki.org/File:Vol4_Page_425_Image_0001.png

The gas lift supply pressure is typically fixed due to the design of the facility. However, the design needs to account for offtake usage based on the forecasted development. If the supply pressure fluctuates, gets reduced, or even stopped, the gas lifted wells may begin to produce erratically or halt production. Erratic production can cause a serious safety risks if the flow regime of the producing wells begin slug flow (see Figure 8); potentially moving or knocking down flowlines as fluid is produced to the production facilities.

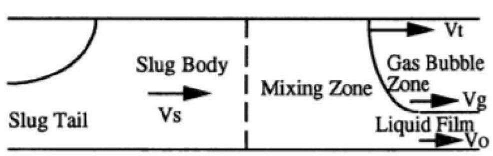


Figure 8: Slug flow in a pipe. (Zhou and Jepson., 1993)

Another concern for daily operation of gas lift is the cost of the gas compression facilities. This can be uneconomic if excessive gas volumes are circulated due to shallow injection depth or if excessive volumes are circulated with diminishing returns (Pittman, 1982).

The amount of backpressure created by any item of production equipment such as wellhead chokes, small flowlines, excessively long pipelines, undersized manifolds, separators, or high compressor suction pressures will seriously impact the operation of a gas lift system. Figure 9 gives an illustration on the effect of backpressure on injection gas requirement and fluid production in a 6,900 ft gas lifted well (Blann, 1984).

Figure 9 shows that at a constant injection-gas rate, the production rate will decrease as the flowing wellhead backpressure increases to the left.

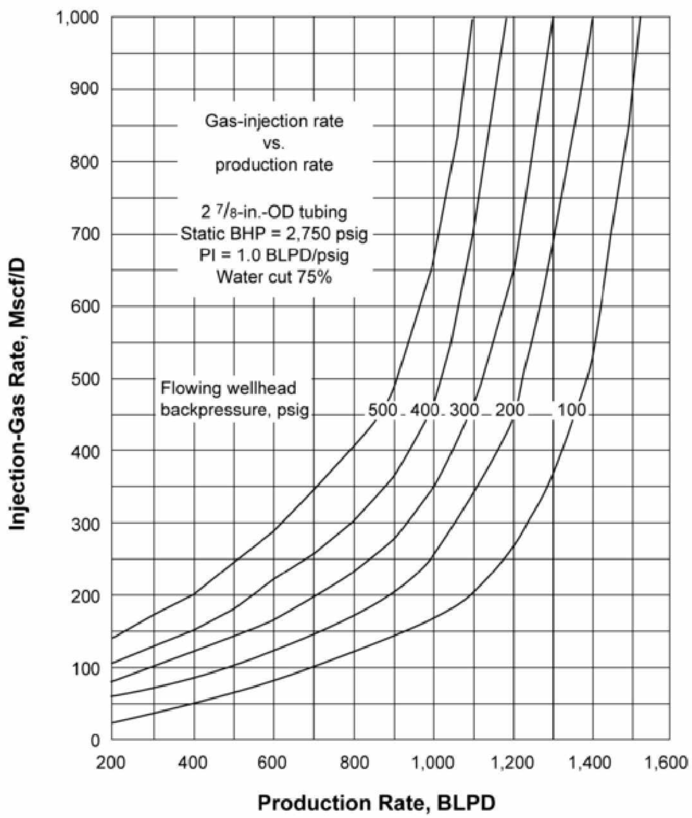


Figure 9: Effect of wellhead backpressure on daily production rates and injection-gas requirements. (Blann., 1984)

Forecasting and optimizing gas lift supply back pressure can be modeled in a physics-based hydraulic network model and is discussed in further detail later.

Another essential component of gas lift surface equipment is the compressor. A centrifugal compressor is the most suitable to supply near-constant gas lift pressure.

Compressor run-time stability is crucial for gas lift operations. However, centrifugal compressors are very sensitive to changes in operating conditions. Compressor operation will become unstable with reduced flow or a reduced inlet pressure. To meet the minimum required flow and inlet pressure conditions for stable compressor operations, prolonged recycle maybe required (Ab Halim et. al., 2016). Figure 10 shows an example of a gas compressor performance curve for a discharge pressure of 90 barg for an HP stage compressor. The compressor must operate within the envelope of the curve in order to operate efficiently.

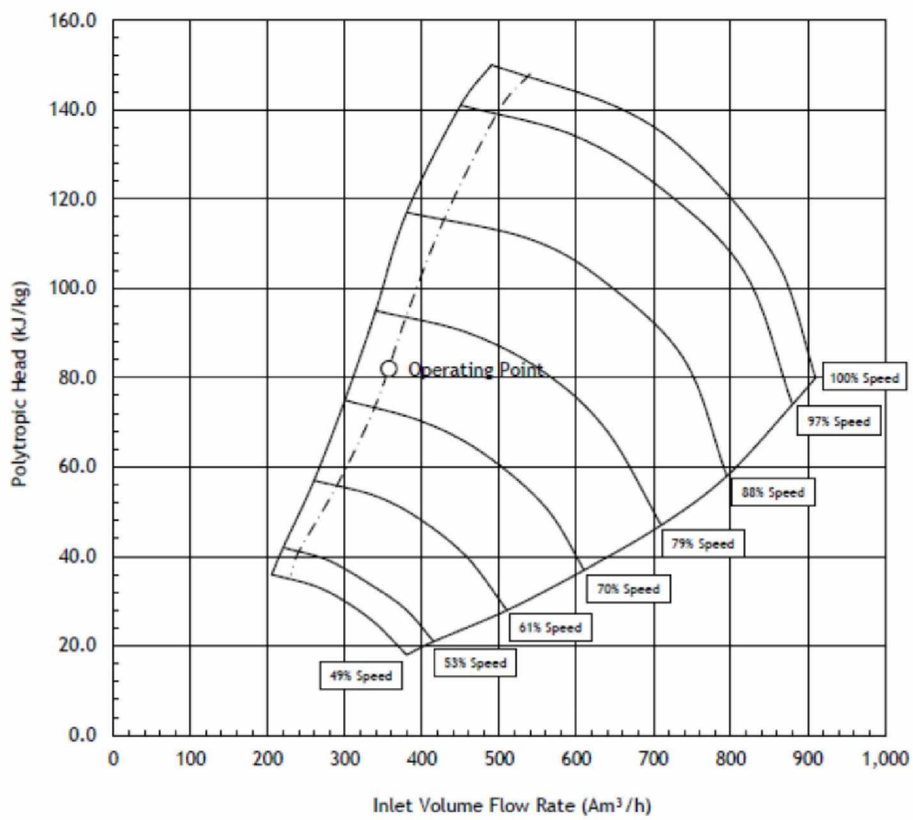


Figure 10: Example of gas compressor performance curve. (Ab Halim et. al., 2006)

Depending on the design of the compressor, ambient temperatures can also affect their performance. In colder, arctic conditions like in Prudhoe Bay, facility equipment such as compressors can run much more efficiently due to the ability to cool down the compressor components at a greater magnitude during the winter months rather than the summer months.

3.0 Gas Lift Optimization

For many years, production engineers have recognized the value of gas lift optimization as a way to generate incremental production and reduce operating expenses (Kanu et al., 1981). Gas lift optimization can be accomplished in many forms. Whether to address the supply pressure issue from the individual gas lift components of each well or tackle it from the surface infrastructure, significant gains in production can be achieved through the optimization of gas lift systems.

Industry experience has shown that gas lifted wells seldom operate under optimal conditions (Schlumberger Gas Lift Design and Technology 1999). The objective of gas lift optimization is to produce the greatest amount of oil for the least amount of gas injected. This can be accomplished by injecting as deep and close to the perforations as possible, lifting from a single point of injection, injecting under stable and steady-state conditions, using the optimal amount of gas given the individual performance requirements per well, by minimizing the backpressure, and by using the most resource-efficient manner possible to allocate lift gas amongst the population of wells.

3.1 Well-by-well Optimization

The most common means of gas lift optimization is well-by-well optimization. The well-by-well basis includes troubleshooting wells, using well models and nodal analysis, replacing gas lift valves, and reducing backpressure on the wells. Each well can be optimized in isolation either through the use of a hydraulic model or by connecting the well to a test separator and varying the gas lift rate to generate a data-driven gas lift performance curve to find the gas lift rate that maximizes oil production (Borden et.al, 2016). The well-by-well approach is often the least expensive and generally produces the greatest production gains according to the Pareto principle. The Pareto principle, depicted in Figure 11, states that well-by-well optimization is the "20% of the effort that yields 80% of the results" (Stephenson et. al., 2010).

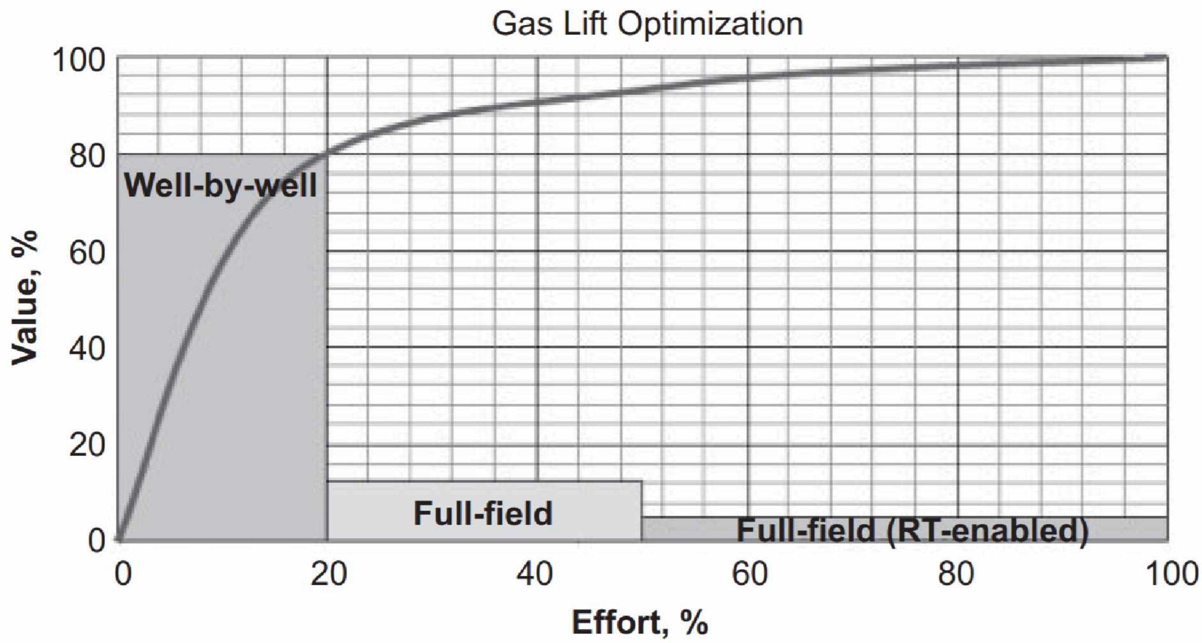


Figure 11: Relative effort vs. value of optimization project classes. (Stephenson et. al., 2010).

The well-by-well issues are mainly focused on well performance and can be categorized in three different ways: inlet issues, outlet issues, and downhole issues. Inlet issues pertain to conditions where gas injection into the well is obstructed or inhibited due to a frozen or plugged injection valve. Inadequate, unstable, or irregular supply pressure to kick off or unload the well also qualify as inlet issues. Outlet issues are considered conditions where the flow downstream of the wellhead is impaired; negatively impacting production. Production chokes, undersized flowlines or manifolds, and high pressure separators are all contributors to outlet issues. Downhole issues commonly encountered are multipoint injection, tubing-to-casing communication, inadequate differential pressure at depth, flow-cutting gas lift valves, temperature locking gas lift valves, and circulating gas above the active fluid level in the tubing (Stephenson et. al., 2010).

The majority of gas lift troubleshooting and diagnostics can be done using a variety of tools and techniques. A common technique is to log the flowing pressure and temperature gradient to determine gas lift entry points into the well. Due to the Joules-Thompson effect, the temperature of the gas drops as it enters the tubing through a small orifice. Figure 12 shows an example log where the temperature drops and deviates from the gradient. This indicates that there is at least some amount of gas entering the tubing through mandrel valve 1.

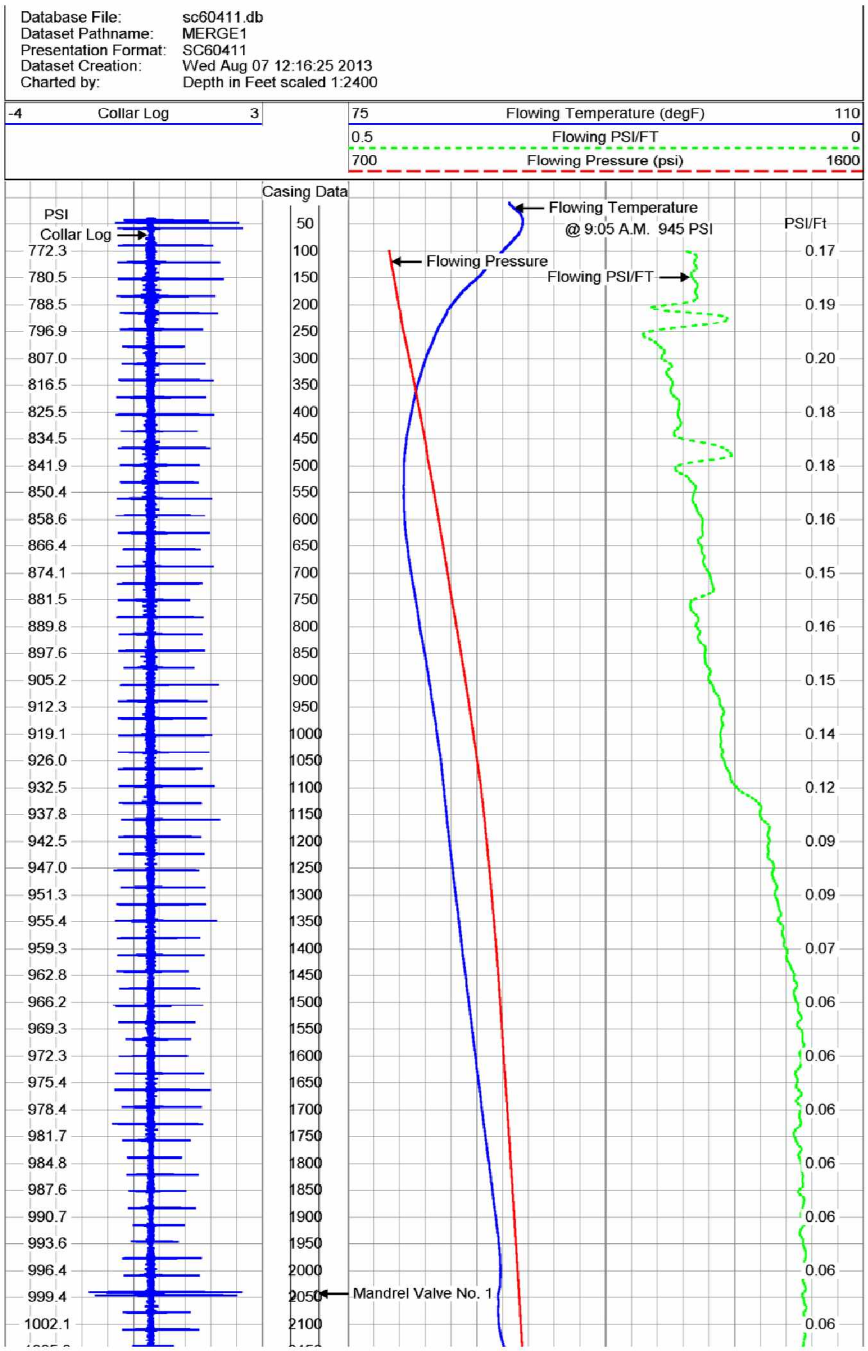


Figure 12: Example gas lift survey log. Adapted from Cardinal Surveys, Retrieved from http://www.cardinalsurveys.com/gaslift/GasLift.pdf.

Another cost effective and common troubleshooting technique is detecting annular fluid levels by taking fluid level shots. Blasts of air into the annular space of a well creates a traveling acoustic wave. That wave travels down the well and echoes back to the surface once it hits a fluid level. This acoustic response can be logged and analyzed to determine the depth of the fluid level (see Figure 13). The annular fluid level indicates the depth at which the gas has point of entry is into the tubing. For example, a well that is properly lifting off of its lower most orifice gas lift valve, should have its annular fluid level at the depth of that lower most valve. This is because the gas would have displaced all the existing annular liquid into the tubing down to that depth during the unloading process.

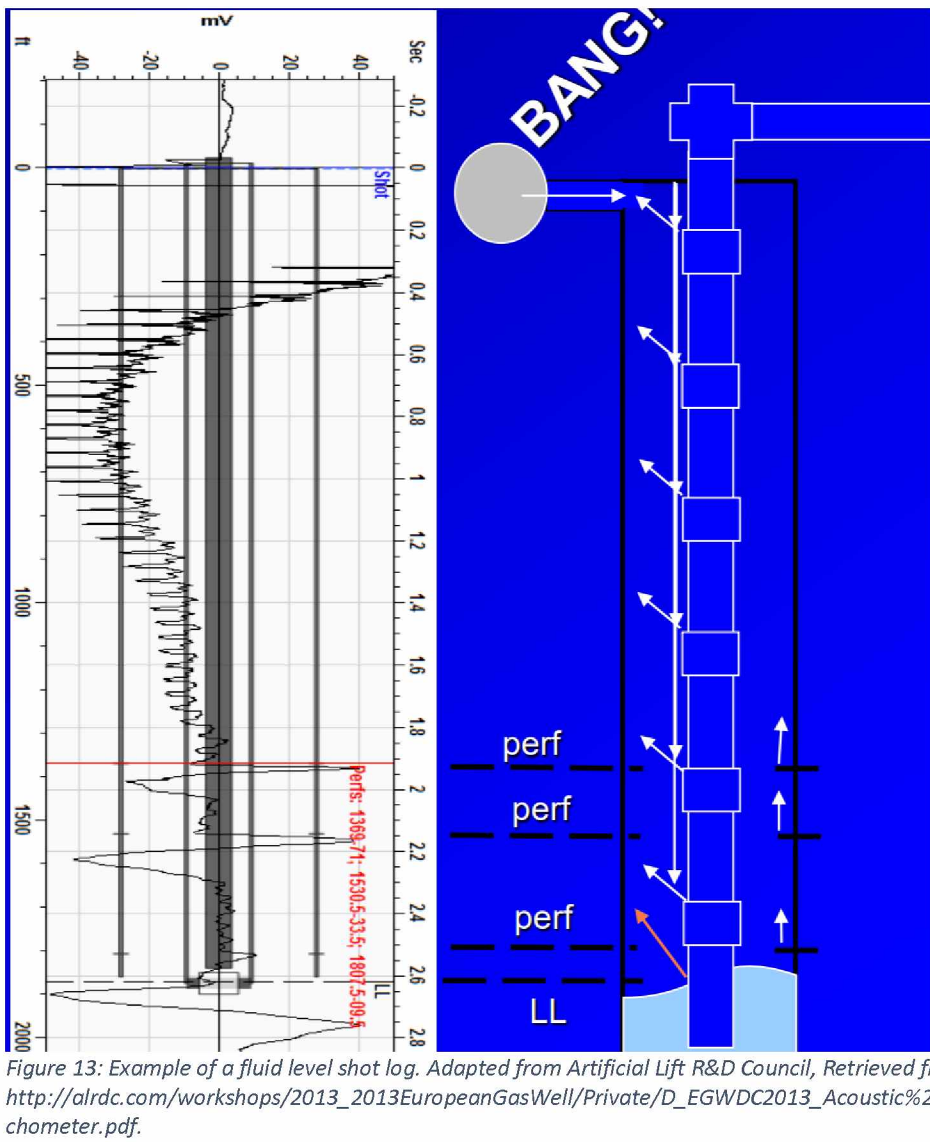


Figure 13: Example of a fluid level shot log. Adapted from Artificial Lift R&D Council, Retrieved from http://alrdc.com/workshops/2013_2013EuropeanGasWell/Private/D_EGWDC2013_Acoustic%20surveillance_Echometer.pdf.

After the culprit is identified from the troubleshooting process, an intervention can usually be performed to fix, optimize or improve the gas lift performance. An example of an intervention is to use a slickline unit to pull a plugged up gas lift valve and replace it with a new functioning one.

Figure 14 is a real world example of well-by-well gas lift optimization. It is a well trend of a particular well in Prudhoe Bay that shows how its production was stabilized by only adjusting the gas lift rate. The light green line is the gas lift injection rate and the white line is the annulus casing pressure. At the start of the plot, the well was injecting an average of 2.0 million standard cubic feet per day (MMScf/d) of gas lift gas. Based on the temperature and pressure trends taken from the surface (white and turquoise lines), this caused severe, unstable flow with annulus casing pressure swings of approximately 400 psi. The pressure swings were stabilized as soon as the gas lift injection rate was increased to an average of 2.5 MMScf/d. This indicates that the well was brought out of the slug flow regime due to the extra gas. To further test the theory, the gas lift injection rate was decreased back down to 2.0 MMScf/d and the well started severely slugging once again.

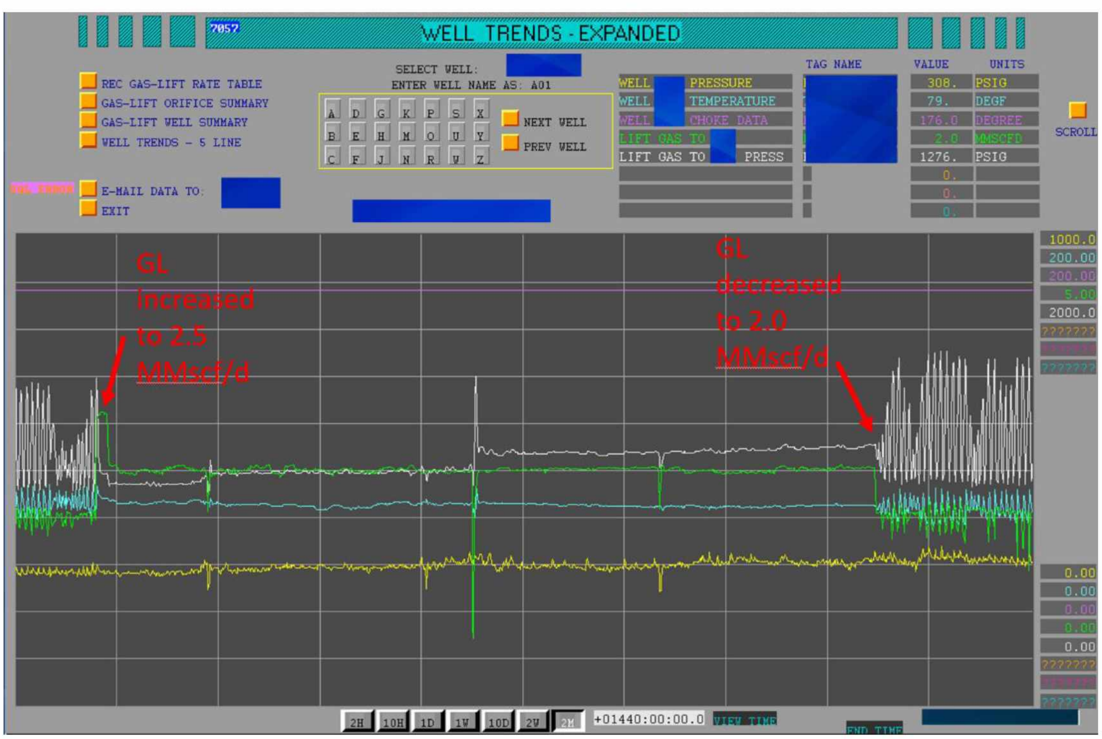


Figure 14: Example well trend for gas lift optimization.

3.2 Well models & Nodal analysis

Since physically troubleshooting and intervening a well requires significant resources and expenses, commercial software can minimize that need by giving the ability to simulate gas-lifted wells. These simulations utilize nodal analysis to determine well performance based on the principle that reservoir inflow and wellbore outflow can be independently characterized as functions of flow rate and pressure (Duncan et. al., 2015).

Nodal analysis can be used to optimize production or injection for existing wells by evaluating the production system performance, calculating the production flow and pressure drop relation that will happen in all the completion system components (Camargo et. al., 2008). In other words, it calculates the balance of energy between the reservoir and the surface within the wellbore. The loss of energy throughout a production system can be visualized in Figure 15.

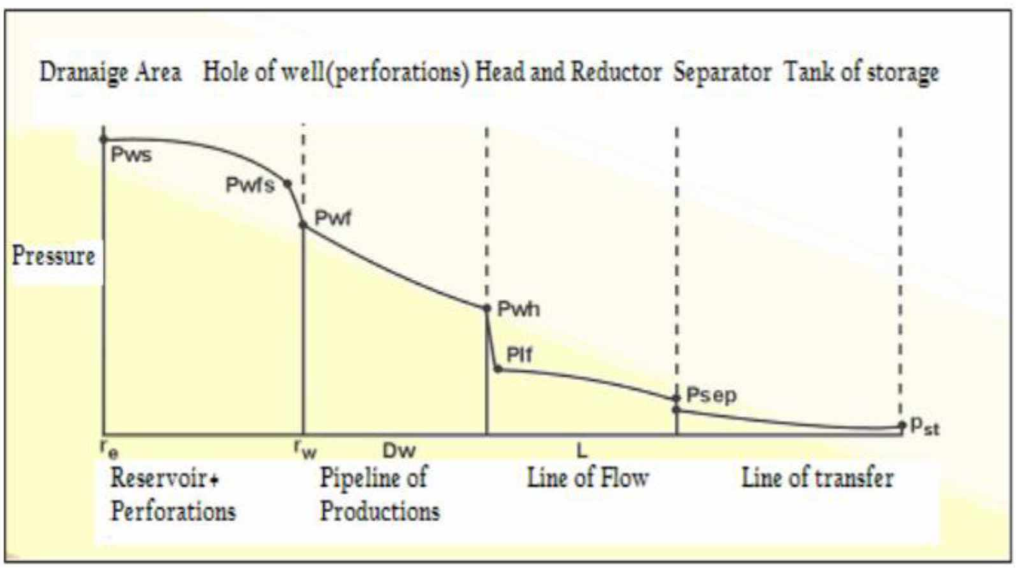


Figure 15: Loss of energy throughout a production system. (Camargo et. al., 2008)

As fluid moves through the production system, the total pressure drop will be the sum of the pressure drops through the various components in the production system. Due to the diverse nature of the gas and fluids produced, the pressure drop is dependent on the interaction between the various components in the system. The pressure drop in a particular component isn't just dependent on flow rate alone, but also the average pressure in the component itself. Thus, an integrated approach is necessary which combines the reservoir and piping components that is analyzed as a whole system.

Figure 16 shows an example of an inflow and outflow performance relationship of a production well. The inflow curve describes how much the reservoir can flow liquid into the wellbore when the well's bottom hole pressure is reduced. Increasing the differential between the reservoir pressure and the bottom hole flowing pressure, also known as drawdown, will increase liquid production from the reservoir. The outflow curve describes what the bottom hole pressure should be for each flowrate inside the tubing. The bottom hole pressure increases as the flowrate inside the tubing increases. The predicted production rate at which the well will flow is determined where the inflow and outflow curves balance and intersect.

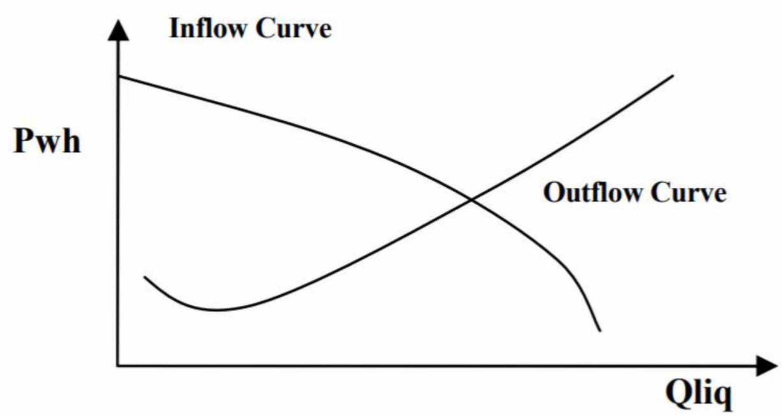


Figure 16: Example inflow & outflow curve.

Well models utilize nodal and system analysis to provide powerful insight on various completion and surface piping scenarios to yield qualitative estimates on expected well and flow behavior. These types of tools can typically help identify opportunities to enhance performance by estimating flowrates, identifying flow restrictions, selecting tubing or flowline sizes, selecting wellhead pressures and choke sizes, or estimate the effects of reservoir pressure depletion. More advanced applications include: evaluation perforation density, gravel pack design, artificial lift design, well stimulation treatments, or the effects of additional surface kit like heaters or inhibitors. The use of well models is a very flexible and robust method that can predict and provide line of sight on project outcomes that help steer important economic decisions.

Figure 17 is a graphical output of a well model of a particular Prudhoe Bay well and provides an example of how useful a well model can be. It shows the difference of how the well will perform with and without gas lift. The brown line is the well's inflow curve and the pink lines are the outflow curves. Since the 'without gas lift' outflow curve doesn't intersect the inflow curve at any point, the well is predicted to be

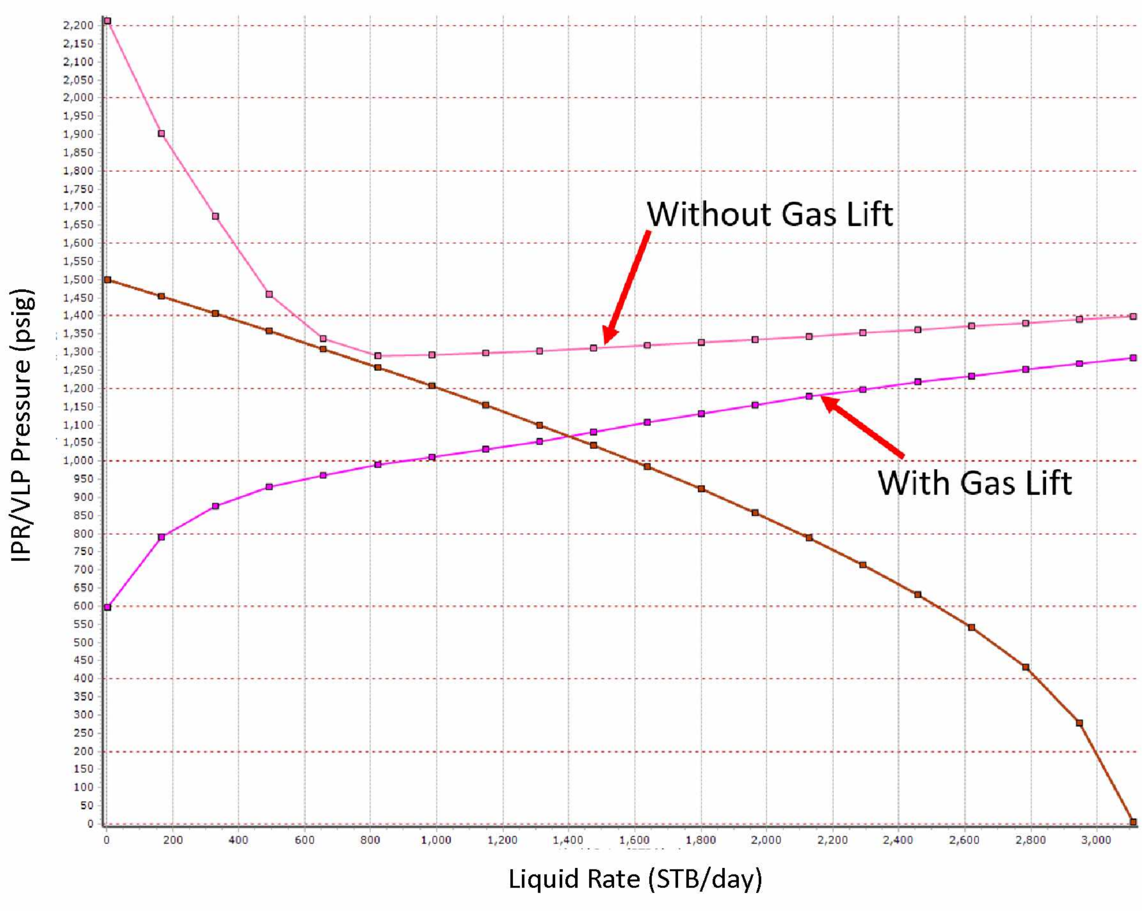


Figure 17: Well model output plot of how a well performs with and without gas lift.

unable to flow without gas lift. On the other hand, the 'with gas lift' outflow curve intersects the inflow curve, thus the well is predicted to flow at a rate of approximately 1,400 barrels of liquid per day (blpd) at a bottomhole flowing pressure of approximately 1,070 psi. Therefore in terms of design and investment, the well will need a gas lift completion and gas supply to flow.

In this case, having gas lift is indeed beneficial. However, exactly how much gas lift should be used? One might think, “More gas lift equals more benefit”. However, gas lift actually has a diminishing value of benefit. At a certain point, the benefits of gas lift will start to decrease after an injection rate threshold is reached. Figure 18 shows an example plot of how gas lift rate affects the total liquid production rate in a well that has 3.958 inch internal diameter tubing. As the gas lift rate is increased, the total liquid rate increases significantly but starts to taper off at 3000 Mscf/d of gas lift. Production then starts to decrease when the gas lift injection rate exceeds 3000 Mscf/d.

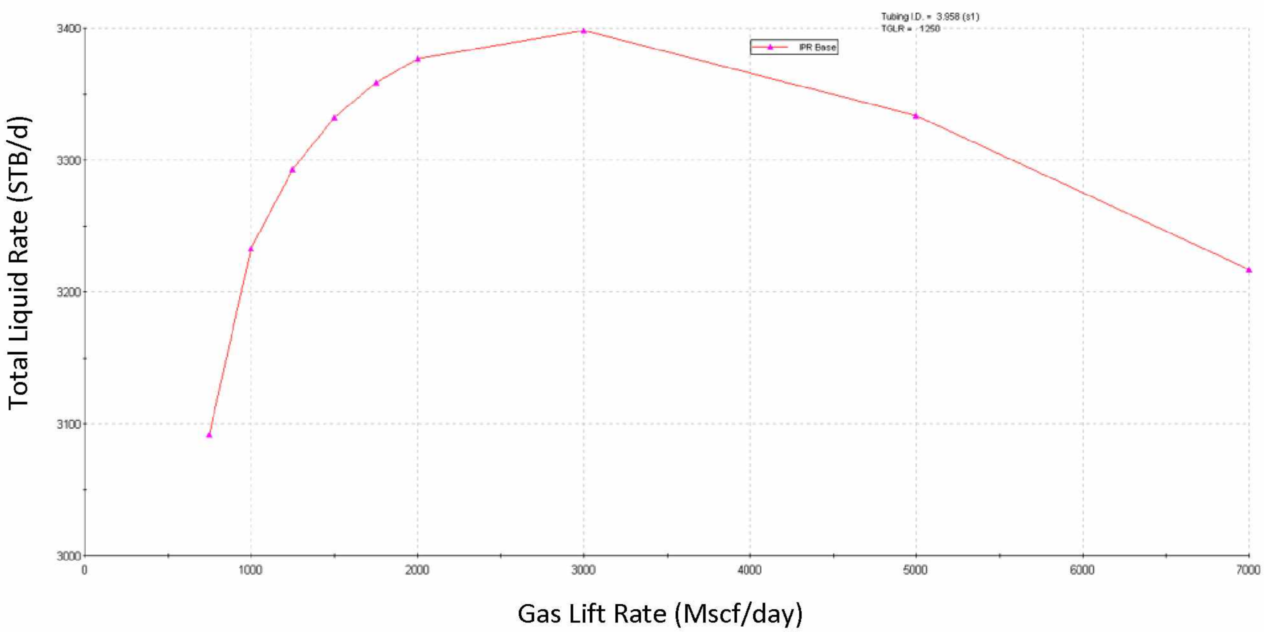


Figure 18: Example plot for diminishing value of too much gas lift.

This phenomenon is largely due to the frictional forces that are experienced in the tubing. Similar to an outflow curve, the higher the flow rate, the more backpressure is generated. The increased backpressure ultimately hinders production. Using a model to calculate and understand how much backpressure is generated from gas lift will help optimize the overall production of the well.

Figure 19 is an example of how using a model can help optimize and maximize the production of a particular well. Using the same well from Figure 17, a system sensitivity analysis was performed in a model to determine the effect of well performance at different gas lift injection rates. The gas lift injection sensitivity range was set between 0 MMscf/d and 7 MMscf/d; generating 8 different outflow curves on the same plot in 1 MMscf/d increments. As seen in Figure 17, the well does not flow at 0 MMscf/d gas lift rate. However, Figure 19 suggests that the well will begin to flow at approximately 1400 stock tank barrels per day (STB/d) with only 1 MMscf/d of gas lift. An increase of 2 MMscf/d, bringing the total to 3 MMscf/d, of gas lift further increased the production rate to 1580 STB/d; an increased delta of 180 STB/d. However, an additional 4 MMscf/d, bringing the total to 7 MMscf/d, of gas lift only increased the production rate to 1650 STB/d; an increased delta of 80 STB/d.

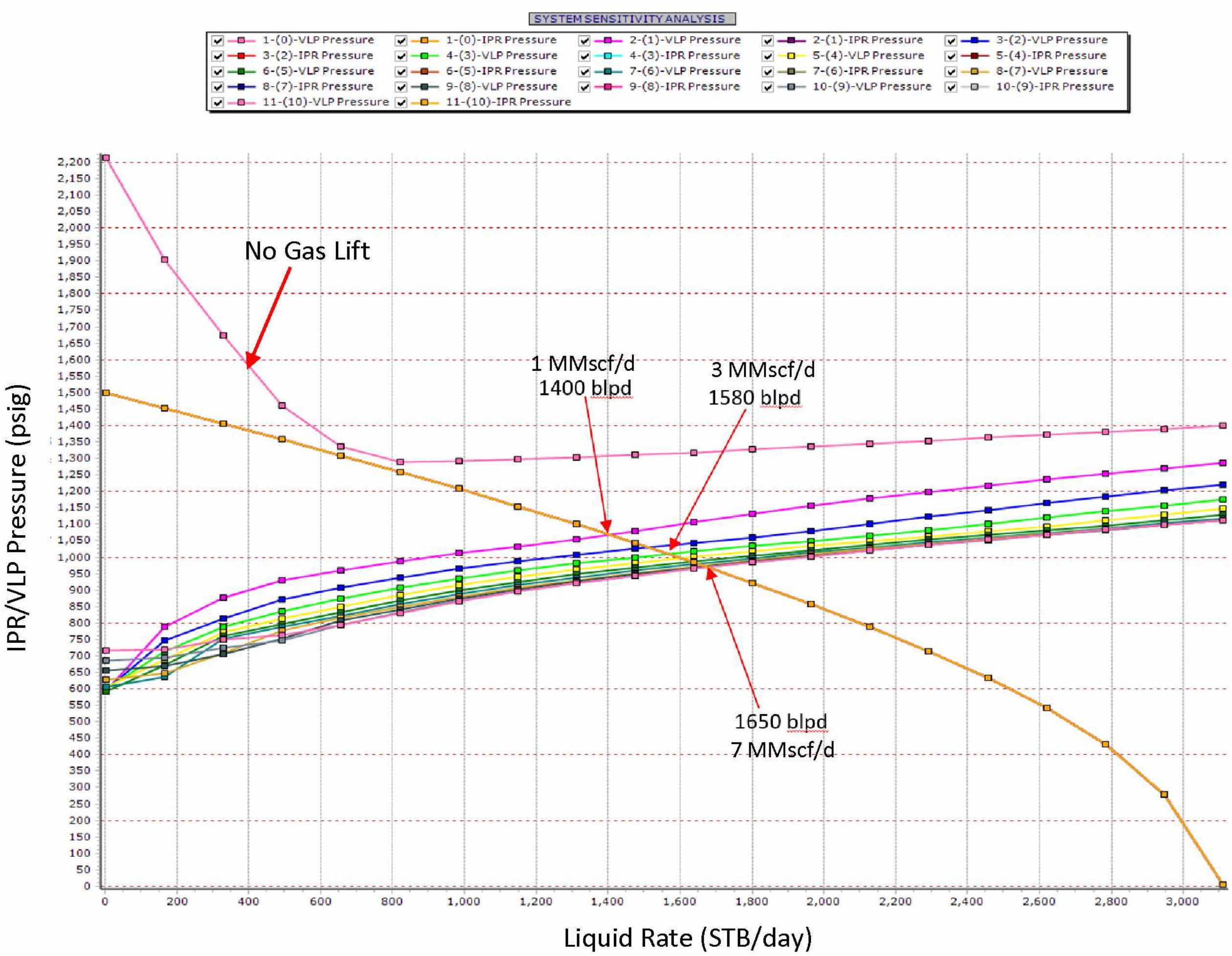


Figure 19: System sensitivity analysis of increasing gas lift injection rate.

Thus the system sensitivity analysis of the model proves the diminishing value of gas lift. Since an increase of 2 MMscf/d of gas lift added an additional 180 STB/d, one might expect that adding another 2 MMscf/d would add another 180 STB/d. However, due to the diminishing returns of gas lift, even tripling the amount of gas lift only added an additional 80 STB/d.

4.0 System Optimization

Production management in large, mature fields can be very challenging due to the multidisciplinary integrated approach to maximize production and extend field life. Understanding how each individual flow component of a field relates to and affects each other is key to optimize the entire system as a whole. An Integrated Production System Model (IPSM) is a model which simulates a field (or group of fields) from reservoir through the wells, pipelines, process facilities, and finally to sales and export (Ageh et. al., 2010). The components of the model should be representative of the real world and be sufficiently accurate in determining the behavior of a production or injection system.

Utilizing IPSM provides a cost effective technique for optimizing and assessing field development concepts. It also provides a means to evaluate various scenarios to explore ideas such as pipeline sizing, well count, well pairing, well phasing, pipeline layout, or process configuration to get the maximum recovery of any particular production system. It can also be used as a tool to evaluate the impact of change on a system for development or maintenance projects (Ageh et. al., 2010).

IPSM modeling techniques are typically applied in green fields to identify and address production bottlenecks or to forecast the production of different development cases (Nazarov et. al., 2014). Bottlenecks are formed when the field's capable production rate exceeds the design capacity of the production system. Bottlenecks can either be addressed, or will slowly become a non-issue as the field matures and production declines. Mature fields generally have less analytical value to IPSM modeling due to lower operating surface pressures, existing facilities, known well performance and studied reservoir geology. However, the processing of reservoir, production and operational data in mature assets through an integrated model can help estimate remaining reserves and can identify real opportunities for optimization not realized by the initial engineered design (Nazarov et. al., 2014).

Additionally IPSM modeling can be incorporated in engineering and equipment surveillance such as gas compressors, gas lift networks, production facilities, etc. Real data from the field such as pressures, temperatures, measured well parameters, reported operational figures, welltests etc. can all be jointly integrated into the IPSM model to keep it up-to-date in real time or to quickly evaluate a scenario using historical data (Nazarov et. al., 2014). Figure 20 describes an example structure of an IPMS toolkit.

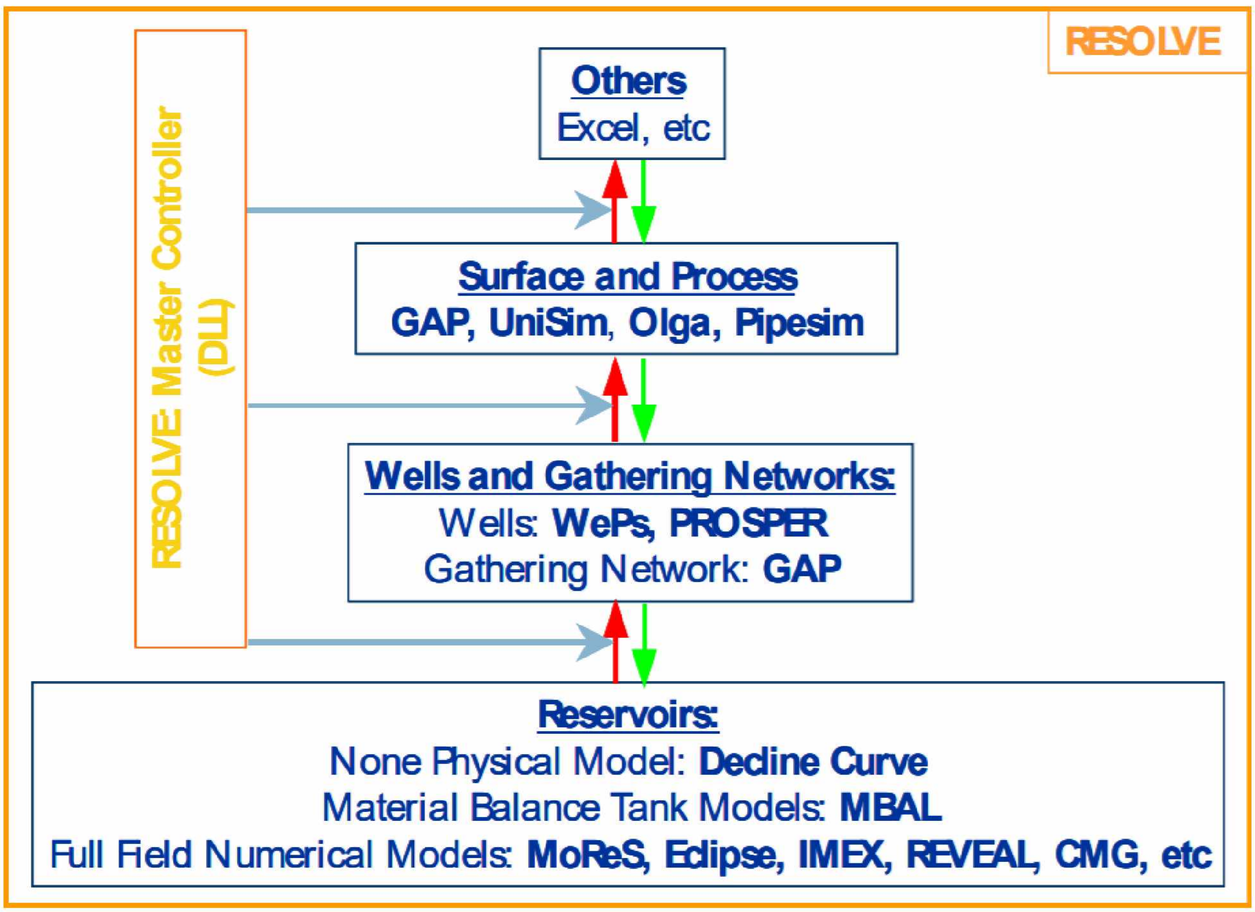


Figure 20: Example structure of an IPSM toolkit. (Ageh et. al., 2010.)

As mentioned previously, the toolkit will normally have the capability to integrate models from the reservoir level all the way to the surface level. A reservoir material balance tank model such as MBAL, can be tied into individual well models called PROSPER. Those individual PROSPER models can then be tied to the surface and process network model called GAP. All these models are tied together on the RESOLVE platform. In RESOLVE, the simulation models are initialized by inputting transmitted and historical production and/or injection data to generate three phase IPR (Inflow Performance Rate) look up tables for each well through PROSPER. This dataset is then simulated and optimized against the user's objective functions in GAP where it solves against the surface and process network of the production system (Ageh et. al., 2010).

Model results are only as good as the input data; as the saying goes, "garbage in, garbage out". The better the quality of the input data, the more reliable and trustworthy the model becomes. Good quality data is quantified by how closely it represents real data. The simulation of the models allows for a trial-and-error approach to investigate different scenarios until an optimal solution is generated. Although this method can be time consuming, it is an ideal way to ensure trial-and-error can be performed safely, and in a cost-effective manner. Safety can be improved by understanding how a production system will react to changes before a physical change is made in the field. For example, if a model suggests that a critical safety limit, such as a pipeline pressure limit, will be exceeded by bringing a production well online into a semi-full production system, a conscious decision would likely be made to leave the well offline; preventing a potentially catastrophic event. Modeling also plays a heavy role in project economics. It helps to determine whether or not a project such as debottlenecking or adding more infrastructure to a production system will increase production benefits and by how much. Therefore, system optimization modeling is very effective in answering specific questions to real world problems. This is the reason IPSM modeling was conveyed to help optimize Prudhoe Bay's West End interconnected and complex production system.

5.0 Prudhoe Bay West End Model

The IPSM software used to build the production system of the Prudhoe Bay West End model was the PETEX toolkit. Of the toolkit, two main programs were utilized: PROSPER and GAP. All the production wells were built individually in PROSPER, while the surface system was built out in GAP.

5.1 West End PROSPER Models

PROSPER software is part of the PETEX toolkit that is dedicated to wellbore nodal analysis. It ties into and works seamlessly in tandem with GAP which is part of the same toolkit that focuses on surface kit. A separate PROSPER model was constructed for each well that is tied to the West End. Figure 21 shows an example of the main landing page in PROSPER.

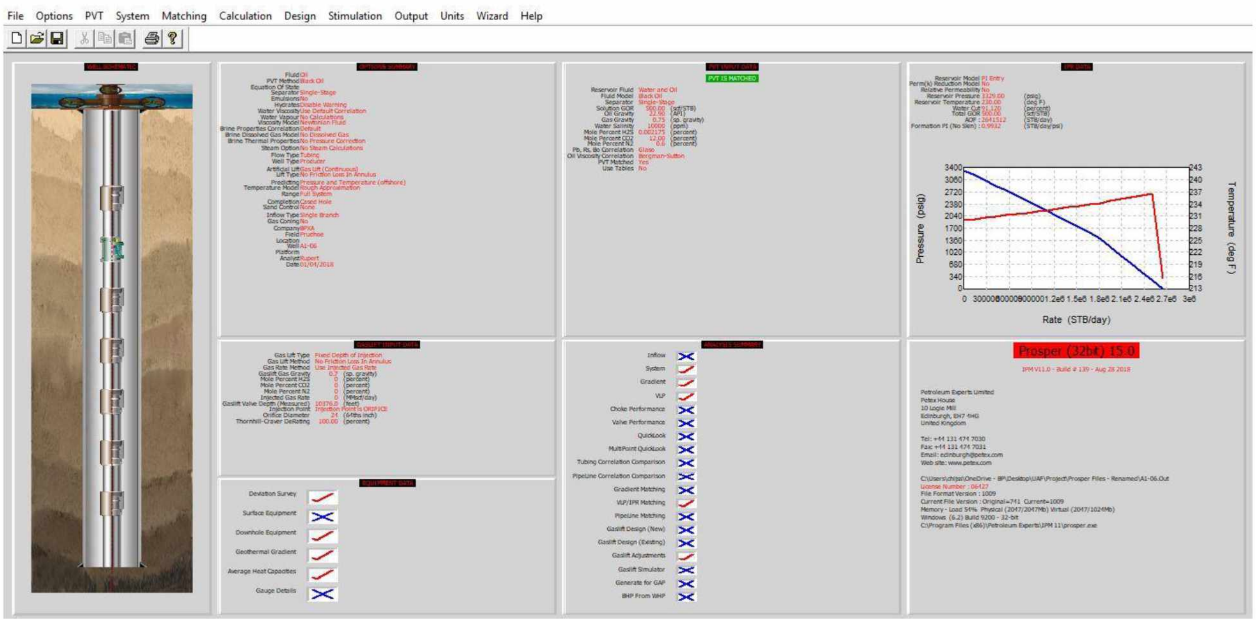


Figure 21: Example of main landing page in PROSPER

Each model has individual well data inputs such as: PVT data, downhole and wellbore geometry, wellbore deviation, gas lift vale depths and sizes, geothermal data, etc. (see Figures 22 & 23).

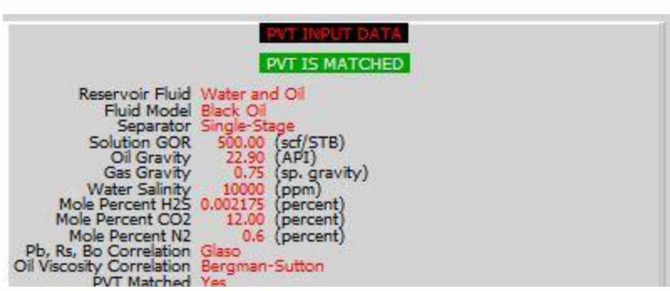


Figure 22: PVT data in PROSPER

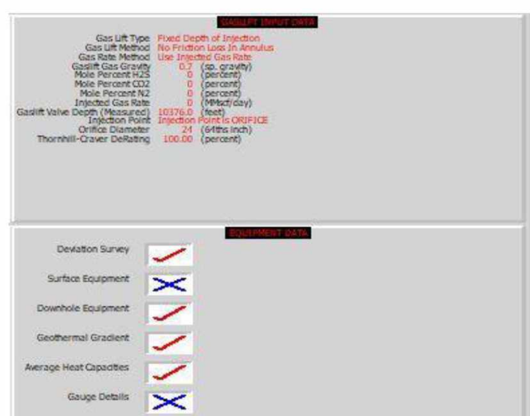
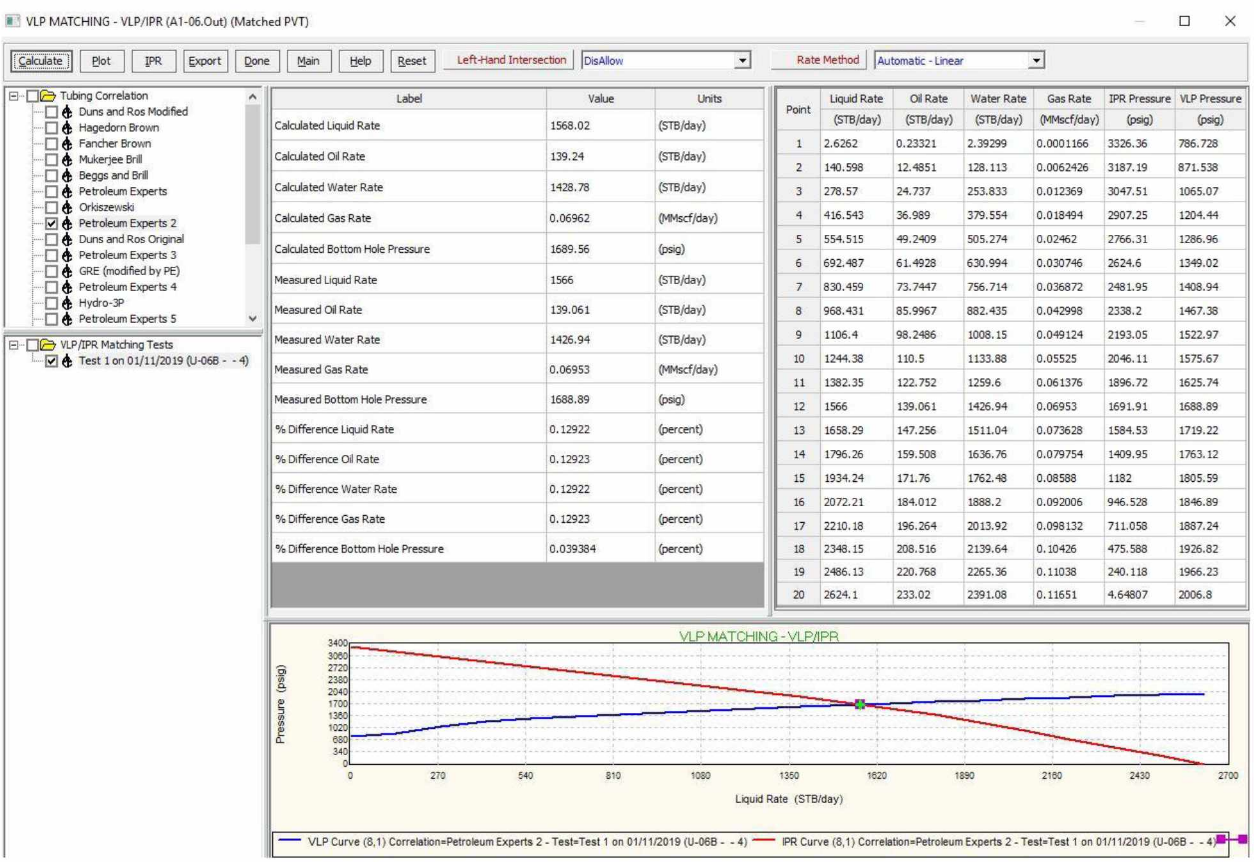


Figure 23: Wellbore data inputs in PROSPER

Metered flow rate, wellhead pressures (WHP) and wellhead temperatures (WHT) from well test data were utilized to determine a multiphase flow pressure drop correlation to predict the flow regimes throughout the tubing. The associated bottom hole flowing pressure (Pwf) and the flowing pressure gradients were also calculated based on the same correlation. The pressure drop correlation helps to determine the necessary bottom hole flowing pressure to support fluid rates with the same well test fluid stream combination of gas-oil-ratio (GOR) and watercut (WC) against the same wellhead pressure. As a result, an outflow curve is generated for the well based on actual well test data. This outflow curve is matched with the generated inflow performance relationship (IPR) curve, using the bottom hole flowing pressure and gross fluid rates from the well test data.



Label	Value	Units
Calculated Liquid Rate	1568.02	(STB/day)
Calculated Oil Rate	139.24	(STB/day)
Calculated Water Rate	1428.78	(STB/day)
Calculated Gas Rate	0.06962	(MMscf/day)
Calculated Bottom Hole Pressure	1689.56	(psig)
Measured Liquid Rate	1566	(STB/day)
Measured Oil Rate	139.061	(STB/day)
Measured Water Rate	1426.94	(STB/day)
Measured Gas Rate	0.06953	(MMscf/day)
Measured Bottom Hole Pressure	1688.89	(psig)
% Difference Liquid Rate	0.12922	(percent)
% Difference Oil Rate	0.12923	(percent)
% Difference Water Rate	0.12922	(percent)
% Difference Gas Rate	0.12923	(percent)
% Difference Bottom Hole Pressure	0.039384	(percent)

Point	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMscf/day)	IPR Pressure (psig)	VLP Pressure (psig)
1	2.6262	0.23321	2.39299	0.0001166	3326.36	786.728
2	140.598	12.4851	128.113	0.0062426	3187.19	871.538
3	278.57	24.737	253.833	0.012369	3047.51	1065.07
4	416.543	36.989	379.554	0.018494	2907.25	1204.44
5	554.515	49.2409	505.274	0.02462	2766.31	1286.96
6	692.487	61.4928	630.994	0.030746	2624.6	1349.02
7	830.459	73.7447	756.714	0.036872	2481.95	1408.94
8	968.431	85.9967	882.435	0.042998	2338.2	1467.38
9	1106.4	98.2486	1008.15	0.049124	2193.05	1522.97
10	1244.38	110.5	1133.88	0.05525	2046.11	1575.67
11	1382.35	122.752	1259.6	0.061376	1896.72	1625.74
12	1566	139.061	1426.94	0.06953	1691.91	1688.89
13	1658.29	147.256	1511.04	0.073628	1584.53	1719.22
14	1796.26	159.508	1636.76	0.079754	1409.95	1763.12
15	1934.24	171.76	1762.48	0.08588	1182	1805.59
16	2072.21	184.012	1888.2	0.092006	946.528	1846.89
17	2210.18	196.264	2013.92	0.098132	711.058	1887.24
18	2348.15	208.516	2139.64	0.10426	475.588	1926.82
19	2486.13	220.768	2265.36	0.11038	240.118	1966.23
20	2624.1	233.02	2391.08	0.11651	4.64807	2006.8

Figure 24: Inflow/Outflow matching to welltest data.

Figure 24 shows an example of an inflow/outflow match result to well test data. In the plot, the square where the two curves meet represent the well test data point and the green cross is what the model calculated. For this particular model, a near perfect match was generated with only a 0.129% difference in measured versus calculated rates. The matched IPR curves represent the reservoir's flow into the wellbore for various flowing bottom hole pressures. The software utilizes the multiphase flow correlation to generate thousands of outflow curves with varying combinations of wellhead pressure, gas-oil-ratio, watercut and gas lift rate. The point where each outflow curve intersects the matched inflow curve represents the well's estimated gross fluid rate for that specific set of parameters.

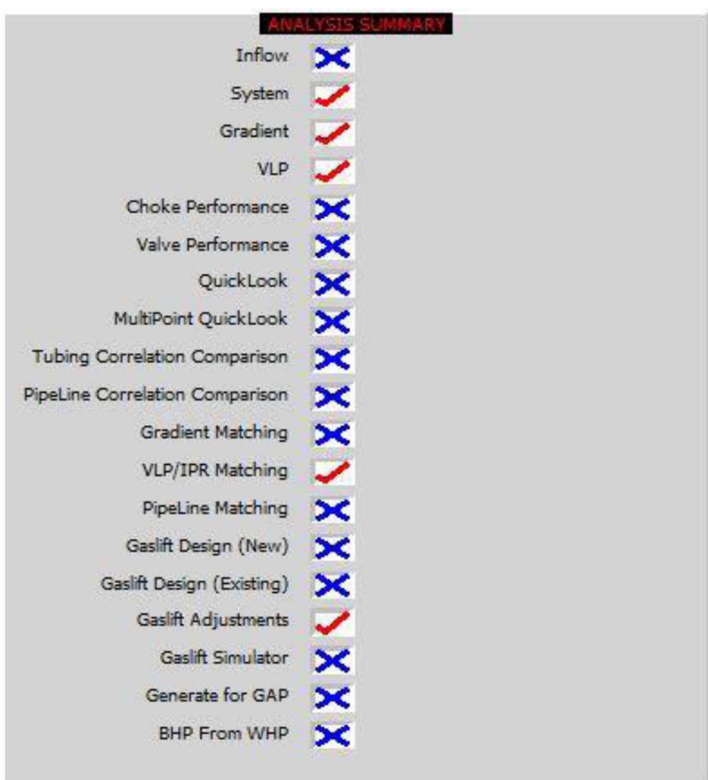


Figure 25: Model sensitivity options for analysis.

The thousands of outflow curves for each well were imported into the GAP multiphase flow surface model simulator so that when the simulator solves pressures and flow rates for each well connected to the surface network, it would use the generated outflow curves to predict a well's behavior in relation to the system network. Figure 25 shows the portion of the model where sensitives can be run for further, in-depth analysis of how a well will behave under certain scenarios. Once a PROSPER model was created and accurately matched to real-world production rates for every production well on the West End, the next step was to build the surface network GAP model to tie everything together.

5.2 West End GAP Production Model

The structure of the West End surface system was built in a multiphase flow production model software named GAP. All the production flow lines on the surface were created in segments. Each segment represents a portion of a flow line with particular attributes such as: pipe inner diameter, total length, internal roughness, elevation, and heat transfer coefficient. The segments are connected to create a production system that represents the actual pipeline configuration of the field. Figure 26 shows the main GAP production model configuration.

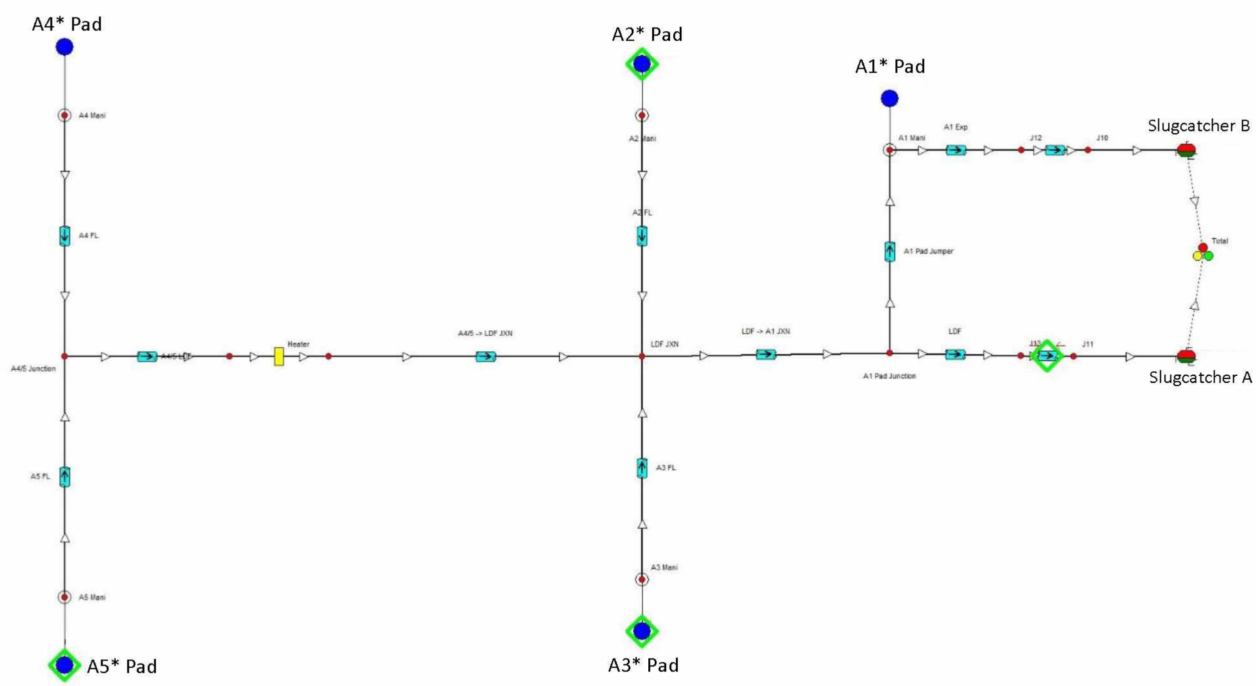


Figure 26: Main West End Production model.

Each well pad on the West End is represented in this model with the dark blue circles. Within each dark blue circle, contains another production model for the individual well pads (See Figures 27-31).

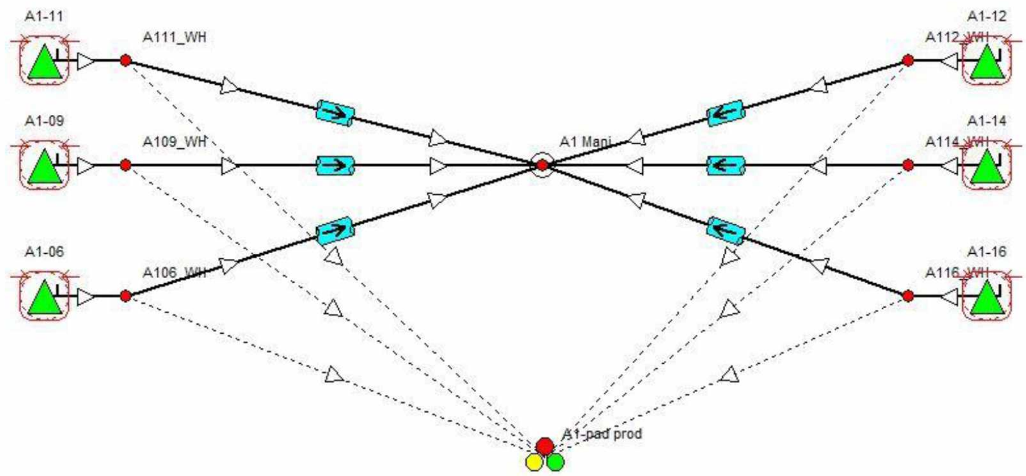


Figure 27: Well Pad A1 production model.*

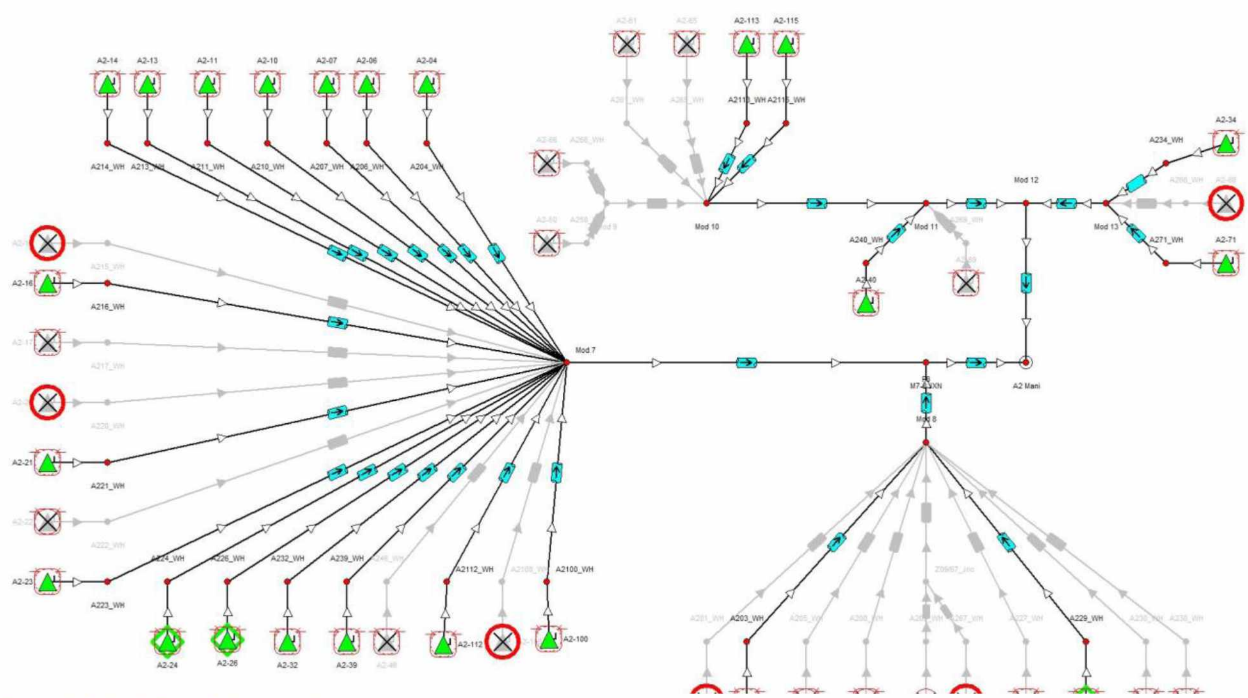


Figure 28: Well Pad A2 production model*

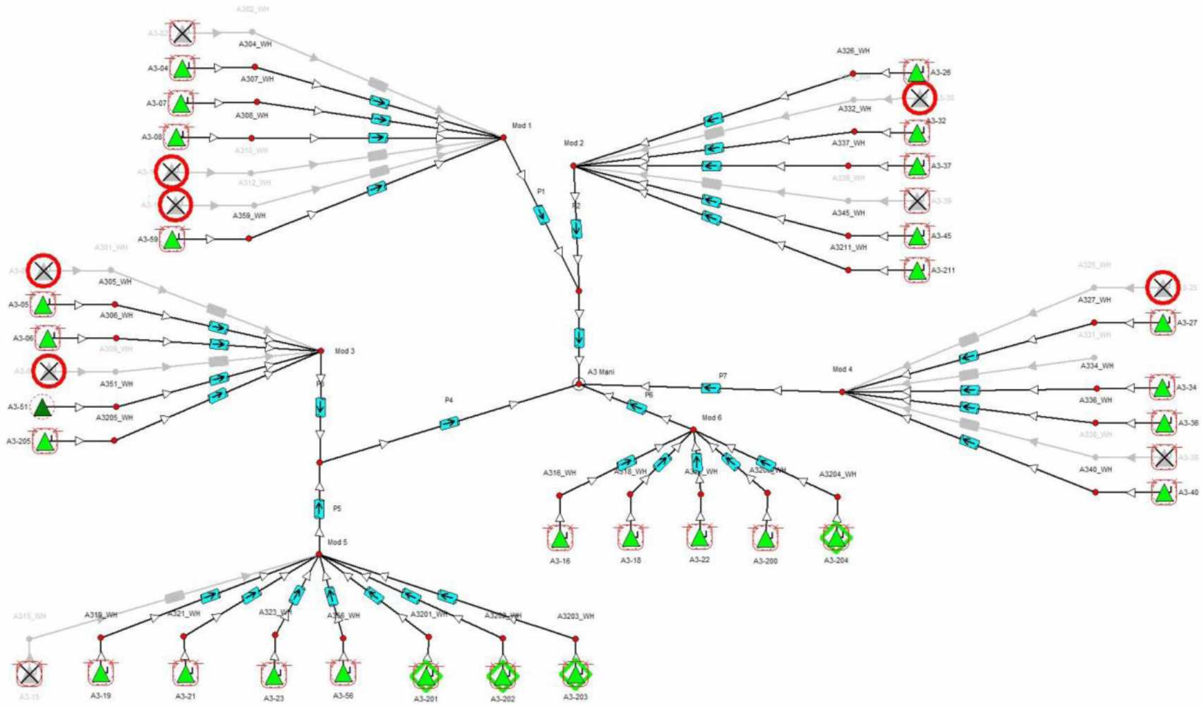


Figure 29: Well Pad A3 production model.*

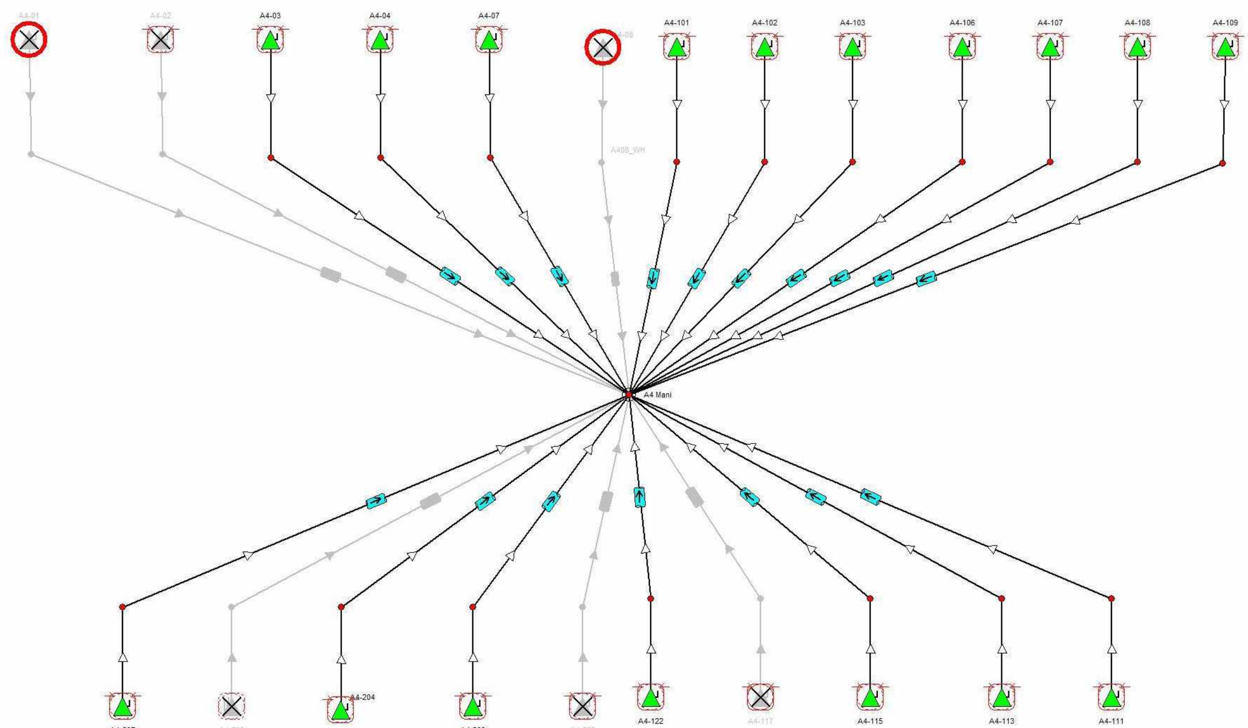


Figure 30: Well Pad A4 production model.*

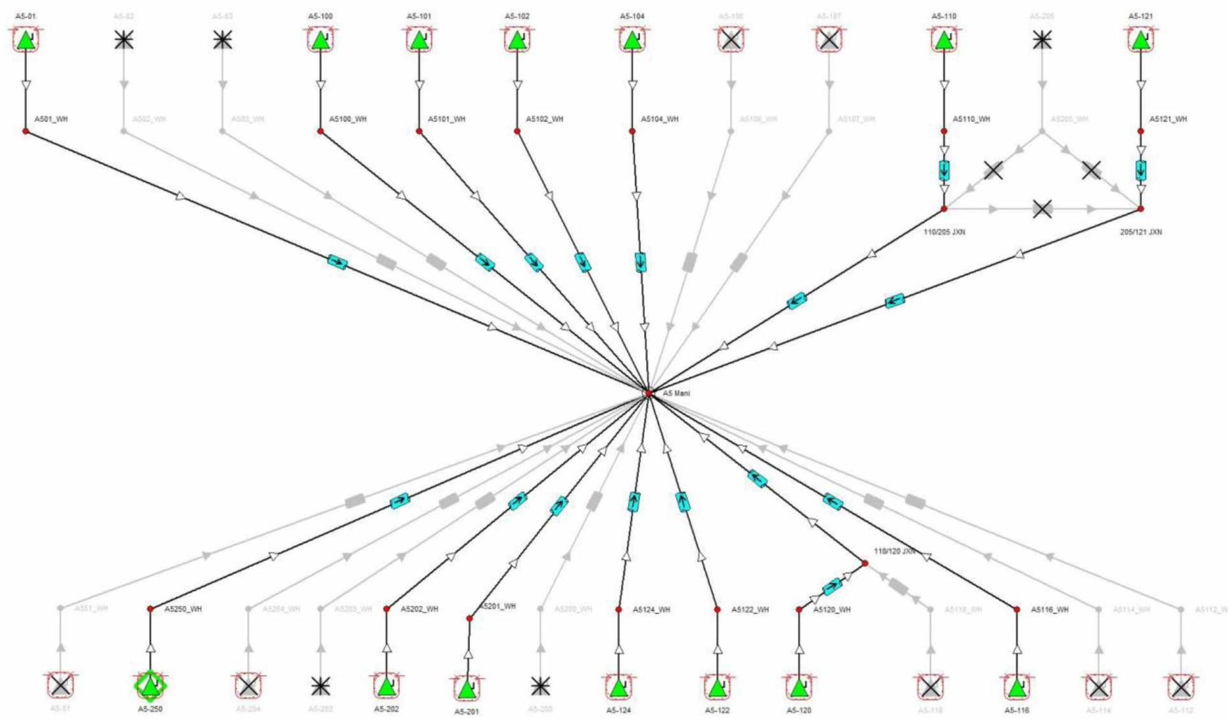


Figure 31: Well Pad A5 production model.*

The light blue segments represent the pipelines and the arrows within the light blue segments represent the calculated direction of flow. The green triangles represent the individual online wells and the grey triangles with either an "X" or an "*" through them are wells that are offline. The combination of online and offline wells were chosen based on a benchmark day of real field data. A benchmark day represents a day of steady production where fluctuations in actual field production can be easily explained and replicated in the model. This way, the output of the model can be referenced and tuned against a day with real and good production data.

From a mathematical solution perspective, it wasn't necessary to have the model look exactly as how the field looks from a bird's eye point of view. However, the models are much more intuitive to work with if the general arrangement of the model components reflect the actual surface network. It is especially useful for a large network model to be arranged and shaped like the actual field surface network so that a real map can be used as a reference to easily find components in the model. The shape or arrangement of the model components does not affect any of the calculations so long as the data input of the individual components such as the pipe diameters and lengths are accurate.

Individual nodes can be seen as small red circles in figures 26-31. These nodes act as computation points for the model when it solves for pressures and flow rates. The nodes connect the segments together and are placed in upstream points where individual wells feed into the surface system. The first stage separator at a production facility was chosen to be the most downstream point of the model because of the separator's constant pressure. The separator vessels have their internal pressures kept constant because they operate on a liquid level control. This constant pressure becomes a mathematical boundary condition for the model to solve for. The solver function could be run once the following conditions were met: all individual well models matched to recent well tests, thousands of VLP curves generated for a range of WHPs and flow streams, surface line segments built and connected, and boundary conditions identified. If the data input to the model matched actual field conditions, the system model's calculated flow rates, pressures, temperatures, velocities, and flow regimes should closely match the actual field. Any calculated results that deviate from actual field conditions is quantified in percent error. If the percent error is larger than what the engineer is comfortable with, the model is fine-tuned further to reduce the percent error.

Due to the sheer size and complexity of the West End model, it initially had a difficult time matching actual field production data. It also had a poor job of predicting production scenarios of when gas supply pressures were low. Back in the year 2013, the EWE LDF flowed at a mixture velocity of ~90 feet per second, allowing many of the operable wells to stay online. Due to the excessive number of wells online, with most needing gas lift injection to flow, the gas lift supply pressures to the well pads on the West End were abnormally low. Theory suggested that the low supply pressure was causing certain wells to "pop off bottom" and inject gas lift in a shallower valve. In other words, the gas lift pressure wasn't enough to keep injecting gas lift into the lower most orifice valve; reducing well productivity. A field trial was conducted to test this theory by shutting in certain wells to boost the gas lift supply pressure. The model was run in tandem with the field trial but failed to accurately predict and match the outcome of the field trial.

In troubleshooting the model, it was found that each gas lifted producing well was lifting from its designed lift point regardless of its casing pressure. This did not reflect reality. For if the gas lift supply pressure to a gas lifted well drops enough, there is a point where there is not sufficient energy to inject the gas at the deepest point; the orifice valve. Since the effect of high gas lift offtake and extensive pipeline pressure drop wasn't being correlated with this shallow lift scenario in the model, an independent gas lift system model needed to be created to account for production changes due to gas lift supply pressure and also changes in gas lift supply pressure due to changes in the production system.

5.3 West End GAP Gas Lift Model

An additional surface model was created in GAP to represent the gas lift system of the West End. The gas lift model needed to tie into the production model to accurately calculate and quantify the effects that gas lift pressure has on production and how changes in production can affect gas lift pressure. The backbone of the gas lift model is reflective of the approximate 15-mile-long gas lift transit line from FAC1*, all the way to pad A5*. From this line, individual well pad lines branched off to form gas lift headers that ultimately fed into the individual wells (see Figure 32).

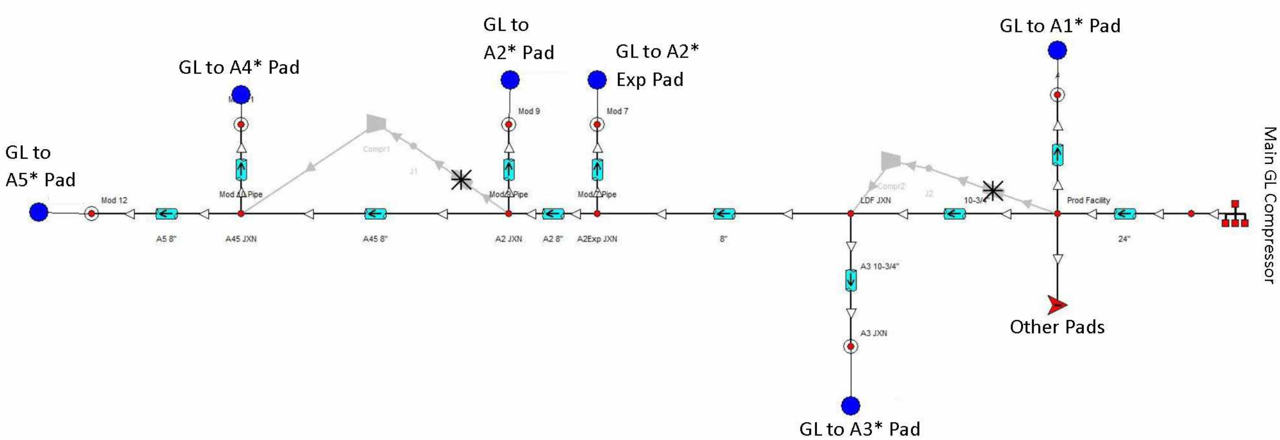


Figure 32: Main West End Gas Lift Surface Model

In the model, the gas lift source begins from the most upstream point; the red manifold icon labeled “GL Main Compressor”. Due to the complex nature of the compressor’s operation and performance in real life, it was opted to simplify its behavior by keeping its output pressure and rate constant. Accurately modeling the compressors behavior meant the need to build an even larger and complex gas lift system model of the entire Prudhoe field. This is due to the fact that the field’s compressors are hydraulically linked and because many wells offtake gas lift between the compressors and the West End. Simplifying the gas lift source increased the likelihood of consistent and realistic model outputs. Theoretically it did not negatively impact the overall reality of the model.

Each individual well’s gas lift line is connected to a “sink” (red triangular icon) that represents the injection point into each well’s production casing. Like the production model, each line segment is connected by nodes that act as both connection and computation points. Each well pad’s gas lift model is shown in Figures 33-38.

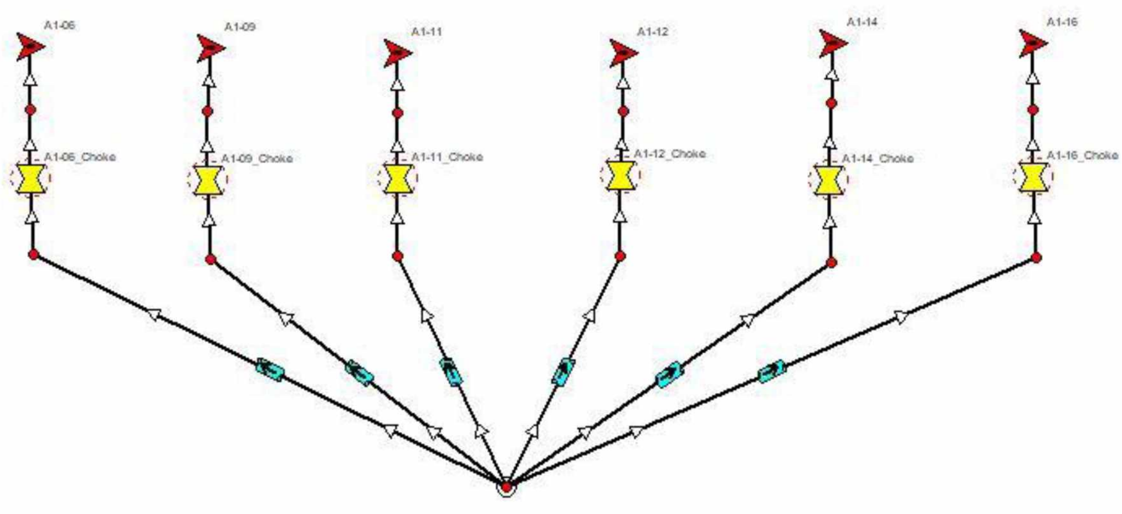


Figure 33: Well Pad A1 gas lift model.*

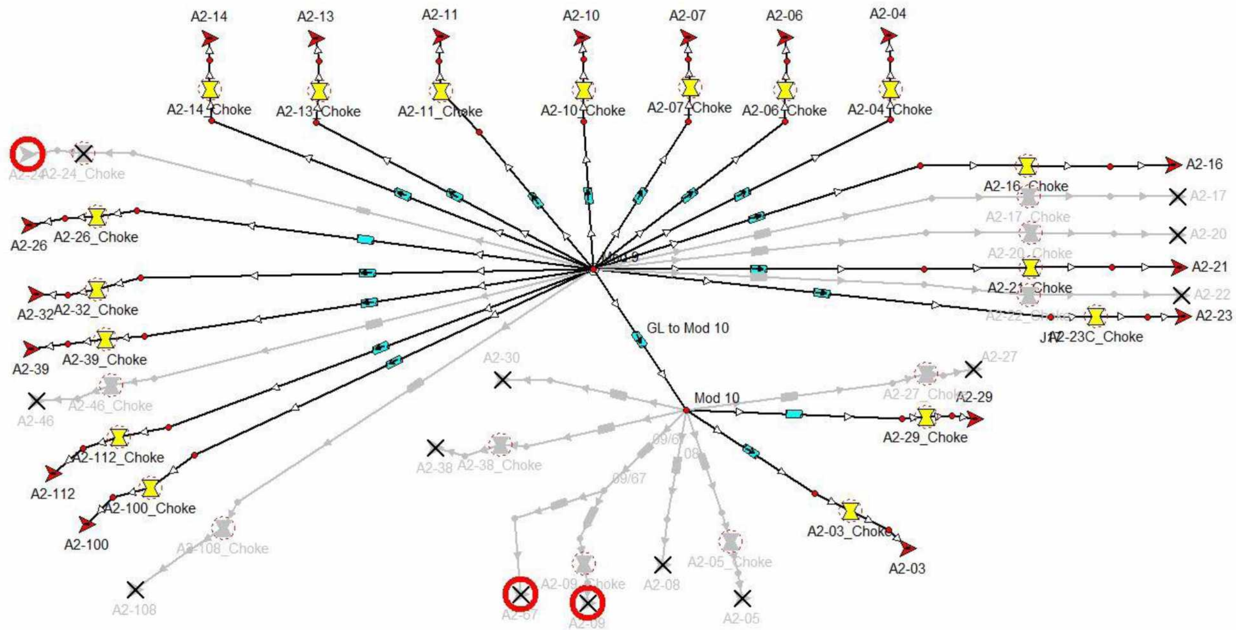


Figure 34: Well Pad A2 gas lift model.*

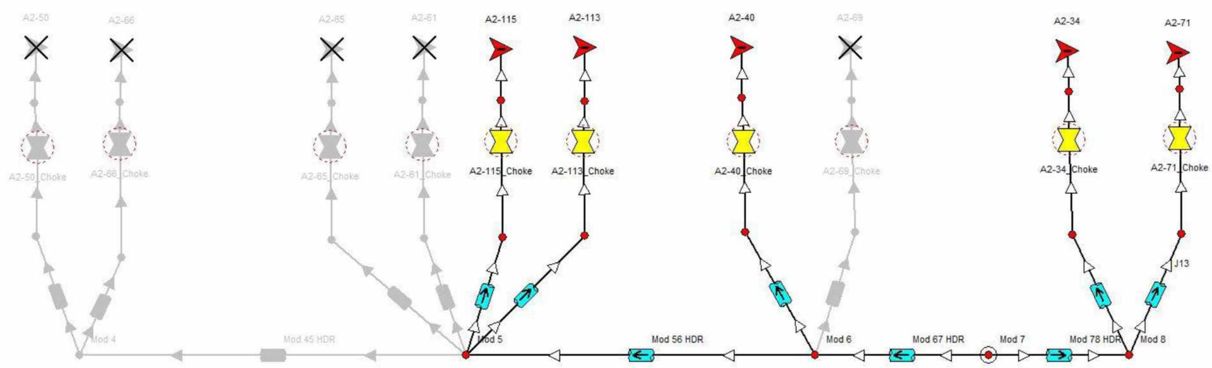


Figure 35: Well Pad A2 expansion gas lift model.*

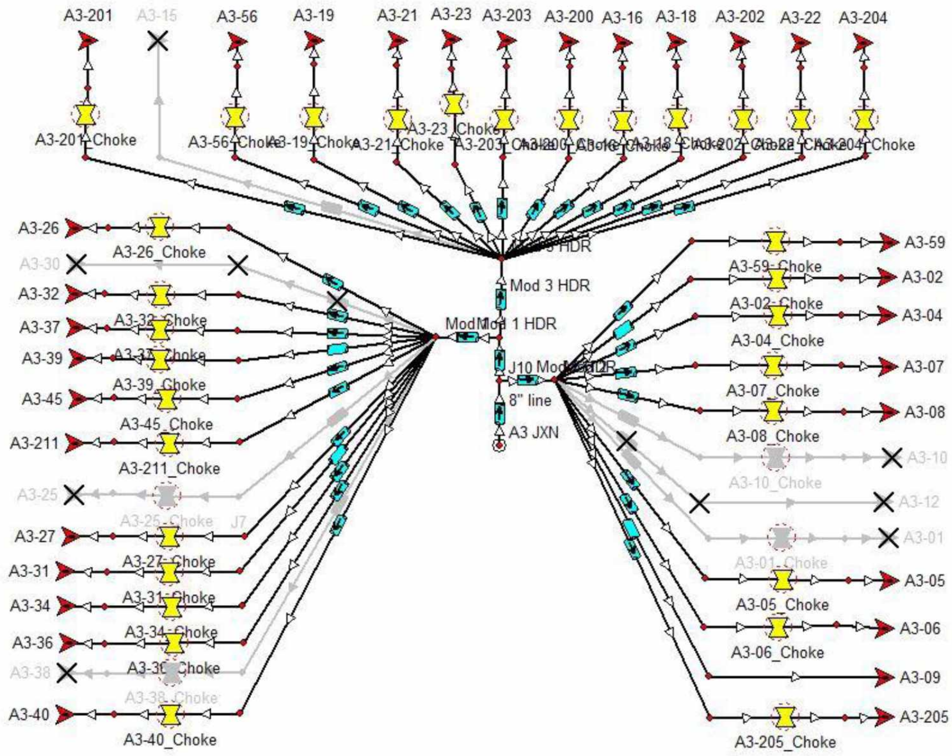


Figure 36: Well Pad A3 gas lift model.*

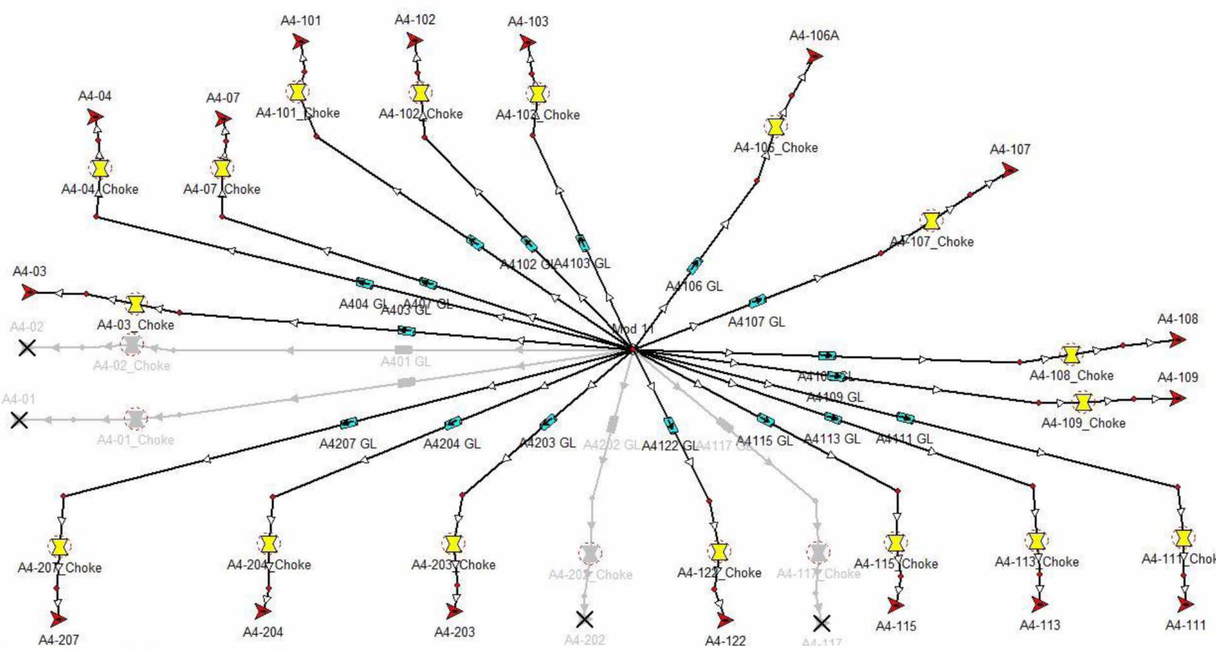


Figure 37: Well Pad A4 gas lift model.*

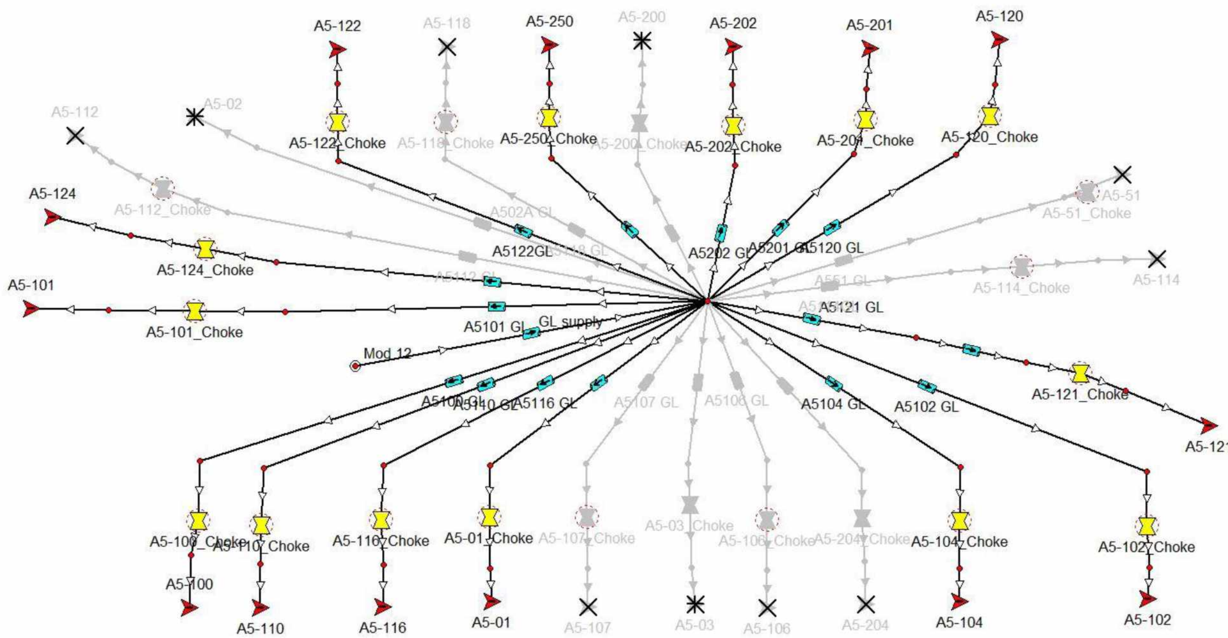


Figure 38: Well Pad A5 gas lift model.*

The dedicated gas lift model was then incorporated with the production model in a way so that the casing pressures calculated by the gas lift model was transferred into the well data of the production model. Gas lift valve designs were programed into each individual well model and several variables were used in the generation of VLP curves such as: well head pressure, watercut, gas oil ratio, gas lift rate, and casing pressure. Each variable needed a realistic operating range for each well. The combination of these variables generated roughly 10,000+ VLP curves per well. This enabled the model to respond to any potential system pressure and conditional change and properly solve the system.

Flow control valves (FCVs) were incorporated into the gas lift model because the casing pressures being passed to the production model were much higher than reality and did not match the field database. Also, significant delta pressures across flow control valves in the field were not being properly reflected in the model. The high casing pressures were causing the model to simulate a deeper lift, increasing production due to increased drawdown; an inaccurate representation of actual conditions. Inline chokes representing the flow control valves were put upstream of the gas lift injection sinks and the actual average delta pressures were loaded as data inputs.

5.4 Matching the Model

The model needed to be proven against actual production data by means of a history match before any predictive study or analysis could be done. This was to ensure that the output of the model closely represented reality within an allowable tolerance. The gas lift model was matched first since it was used as an input for the production model. Using actual field data for gas lift injection rates, upstream supply pressure, and actual differential pressures across the flow control valves, the individual well casing pressures were solved in the model and compared against actual casing pressure data from the field. The initial results matched reasonably close to the field data, but it needed minor individual adjustments. These adjustments involved tweaking pipeline friction factors, detailed inner diameter step changes for certain pipelines, and the inline chokes. Not only did the individual well casing pressures need to closely match the field data, but the supply pressures to each pad also needed to match. After a substantial amount of trial and error, the gas lift model was matched to an arbitrary ±10%. Figure 39 shows the actual vs simulated percent error for every well's casing pressure in the gas lift model.

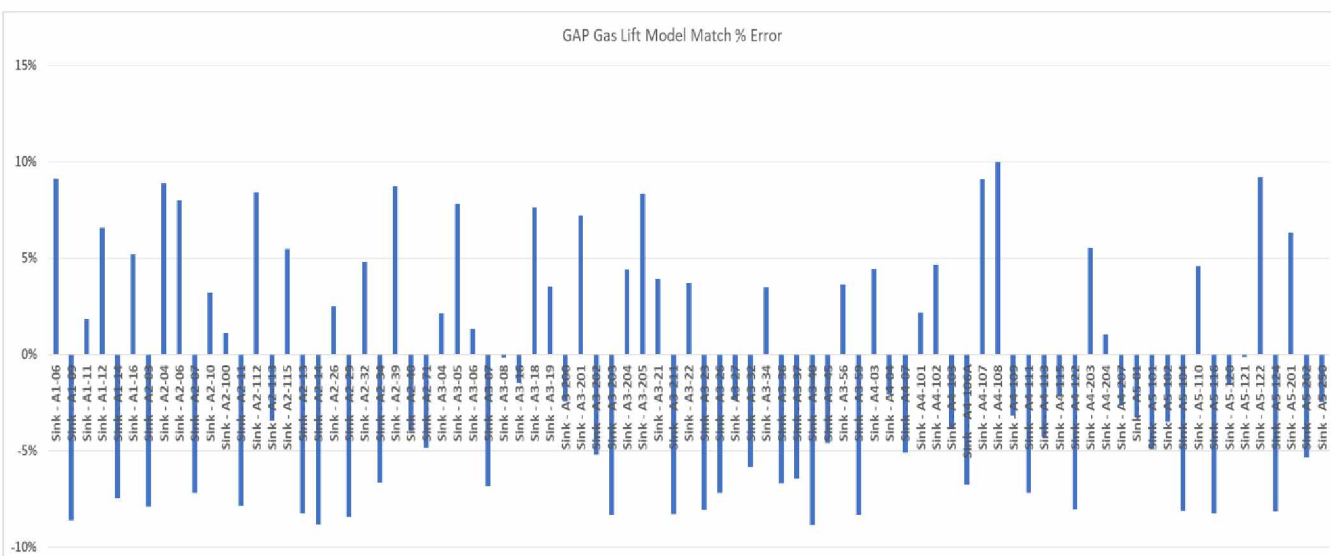


Figure 39: Graphical representation of the gas lift model matched casing pressure +/- 10%.

After the gas lift model was matched to an acceptable range of ±10%, the casing pressures generated from the gas lift model were then utilized into the production model. The production model's simulated results were compared to actual field production data of a benchmark day. A benchmark day is a day when production in the field was in a normal and stabilized condition where fluctuations in production can be easily explained and considered in the model. Thus, the average production rate of the benchmark day will be more representative and comparable to the static nature of the production model.

The match of the production model was not close at first. However, similar to the gas lift model, several tweaks were made to get the model to match closer to actual production data. Some tweaks included: adjusting well IPR curves, VLP curves, watercuts, gas oil ratios, and well head pressures for several individual wells. Table 1 shows the final model match results of the production model grouped into individual well pads.

Table 1: Production model matched to field production data.

	Simulated			Actual			% Error		
Pad	Oil (STB/d)	Water (STB/d)	Gas (MMscf/d)	Oil (STB/d)	Water (STB/d)	Gas (MMscf/d)	Oil (STB/d)	Water (STB/d)	Gas (MMscf/d)
A1*	6677	16959	10.59	6971	16724	11.31	4.22%	-1.41%	6.38%
A2*	8653	17137	13.97	8737	17600	14.02	0.96%	2.63%	0.36%
A3*	8974	34276	20.26	8811	31550	20.89	-1.85%	-8.64%	3.02%
A4*	10403	24468	26.44	10123	24608	26.11	-2.77%	0.57%	-1.26%
A5*	2383	10289	16.87	2318	10385	17.34	-2.80%	0.92%	2.71%
Total	**37090**	**103129**	**88.13**	**36960**	**100867**	**89.67**	**-0.35%**	**-2.24%**	**1.72%**

Although several well pads had error deviations larger than ±5%, the total percent error came out to be less than 3% (last row of Table 1). This small margin of error was deemed acceptable due to the large number of variables and assumptions incorporated into the model. The effort of reducing the percent error any further would no longer outweigh the benefit and would likely not reduce the uncertainty of the model as a whole.

5.5 Applying the Model to Simulate Scenarios

It was theorized that the lack of gas lift supply pressure due to the long supply line having an extensive pressure drop and too many wells needing gas lift was negatively impacting production. The low gas lift supply pressure was not sufficient enough to allow several wells to lift from their deepest gas lift valves; impeding production. So theoretically, production could be improved by boosting the gas lift supply pressure with a compressor or by shutting in wells that took too much gas lift. Given the amount of time and cost it would take to build and integrate a new compressor in the field and the loss of production shutting in wells would cause, the models were used to evaluate and estimate the benefit of such a large investment.

With an acceptable history match for both models, several different scenarios were created and simulated to study the responses in the production system due to major changes to either surface infrastructure or online wellstock. As mentioned previously, four main scenarios were built and evaluated: 1) A base case to match the model to real production numbers; 2) Adding an extra compressor before Wellpad A3* to boost supply pressure (see Figure 40); 3) Adding an extra compressor before Wellpads A4* & A5* to boost the supply pressure (see Figure 41); 4) Shutting in lower marginal gas lift wells to reduce the number of gas lift offtake.

The four scenarios are compared to determine which approach would yield the most benefit from both an operational and production standpoint.

5.5.1 Scenario 1 - Base case

The base case was created during the history matching phase. The model needed to be matched against actual historical production data to decrease the uncertainty of the model and to provide a solid baseline against different scenarios. The deviations of the model output due to the different scenarios were held with more confidence because of the well-matched base case. The results of the base case can be seen in Table 2 in section 5.4. The final simulated production rates of the base case resulted in 37,090 bopd, 103,129 bwpd, and 88.13 MMscf/d of gas.

5.5.2 Scenario 2 - Additional Compressor Before Wellpad A3*

In theory, production could be improved by boosting the gas lift supply pressure with a compressor. However, the location of the compressor needed to be evaluated since the biggest culprit against the gas lift supply pressure was the length of the supply line. Thus, was it more or less beneficial to set a booster compressor relatively upstream or further downstream? In this scenario, a booster compressor was added into the model upstream of Wellpad A3*. As seen in Figure 40, the yellow icon representing the compressor was added as an alternative route. Thus, in order to route all the flow through the compressor, the original route had to be disabled in the model.

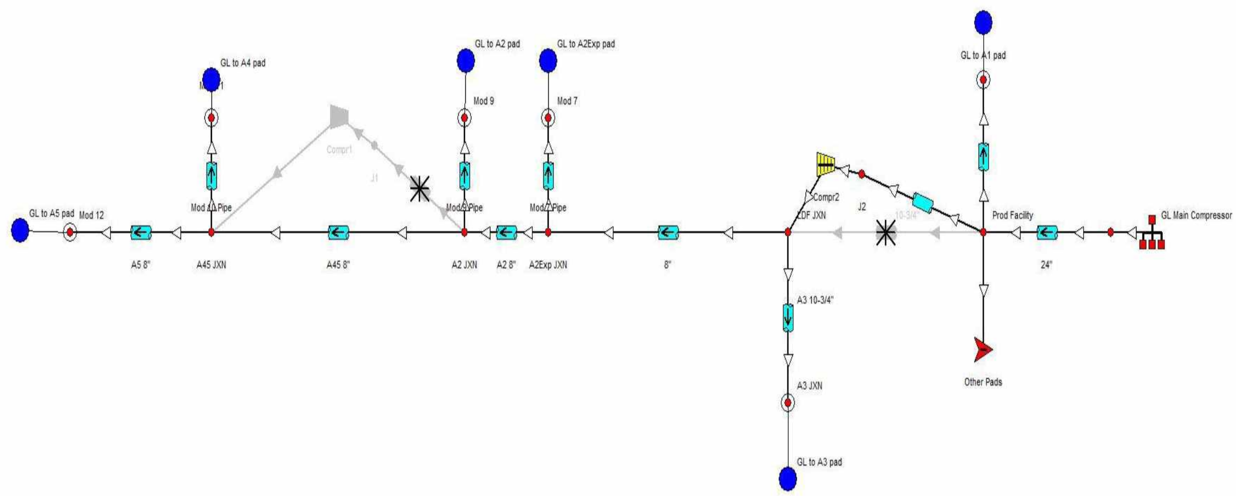


Figure 40: Gas lift model with a booster compressor before Wellpad A3.*

This was still an accurate representation of the field infrastructure as the length and diameter of the pipeline did not change. The booster compressor output was set to a constant 2020 psi, which is the same output pressure from where the gas lift supply originates at FAC1*. Higher output pressures were not used because safety limits surrounding the maximum burst pressure of the gas lift supply pipeline had to be considered.

The simulation of this scenario resulted in a reasonable increase of production rate: 37,582 bopd, 104,260 bwpd, 88.36 MMscf/d. The gas lift supply pressure at the end of the line (Wellpad A5*) increased from the 1638 psi base case to 1848 psi. Based on these results, boosting the gas lift supply pressure before Wellpad A3* should increase overall production by roughly 492 bopd.

5.5.3 Scenario 3 – Additional Compressor before Wellpad A4*

Inserting a booster compressor farther downstream was also evaluated because it was believed that wellpads A4* and A5* were struggling the most in terms of having enough gas lift supply pressure to properly gas lift the wells. It was assumed that the wellpads upstream of A4* and A5* had sufficient gas lift supply pressure for their wells. As seen in Figure 41, a booster compressor (yellow icon) was added into the model upstream of Wellpad A4* with its original routing disabled.

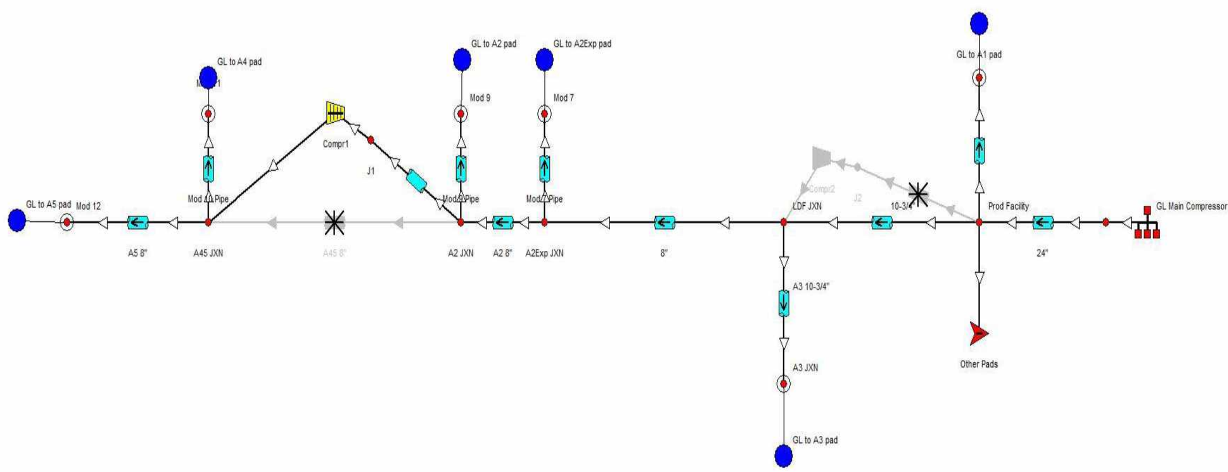


Figure 41: Gas lift model with booster compressor before Wellpad A4.*

Again, the booster compressor output was set to a constant 2020 psi, which is the same output pressure from where the gas lift supply originates at FAC1*. Higher output pressures were not used because safety limits surrounding the maximum burst pressure of the gas lift supply pipeline had to be considered. The simulation of this scenario resulted in a marginal increase of production rate: 37,163 bopd, 103,241 bwpd, 88.14 MMscf/d. The gas lift supply pressure at the end of the line (Wellpad A5*) increased from the 1638 psi base case to 2018 psi.

Based on these results, boosting the gas lift supply pressure before Wellpad A4* should increase overall production by roughly 73 bopd.

5.5.4 Scenario 4 – Shutting in Lower Marginal Gas Lifted Wells

Another method to boost overall gas lift supply pressure was to reduce the number of wells taking gas lift rate. Fundamentally, reducing the amount of offtake from a distribution system will ultimately increase the supply pressure. However, since producing wells had to be shut in, there was a risk that the loss of production rate from the producing wells would outweigh the production gain from boosting the gas lift supply pressure. A manual optimization method was performed by means of a wellsort to minimize that risk.

The wellsort consisted of all the active wells in the model were listed and sorted by their gas lift to oil ratio. In this case, meaning the higher the gas lift to oil ratio, the less competitive the well was. If a well took a significant amount of gas lift to produce a small amount of oil, it was not considered a competitive well to keep online. To test this theory, five of the least competitive wells were chosen from the wellsort and shut-in in the model. The total rate that was shut-in were summed up to be 227 bopd, 7937 bwpd, 0.78 MMscf/d of formation gas, and 11.1 MMscf/d of gas lift gas.

The simulation of this scenario resulted in a surprising increase of production rate: 37,452 bopd, 96,733 bwpd, 87.33 MMscf/d. The gas lift supply pressure at the end of the line (Wellpad A5*) increased from the 1638 psi base case to 1692 psi. Based on these results, shutting in wells actually increased overall oil production by roughly 362 bopd.

5.6 Summary of Results

The simulation results of the different scenarios are compiled in table 3. Several surprising outcomes were realized from this study. First, it was hypothesized that adding a compressor upstream of Wellpad A4* (scenario 3) would yield a higher production rate than a booster compressor upstream of Wellpad A3* (scenario 2). This was because Wellpads A4* and A5* had the lowest gas lift supply pressure to begin with and it was thought that boosting the gas lift pressure at those wellpads would provide a substantial gain in production. As it turns out, this was not the case. According to the model, inserting a booster compressor upstream of Wellpad A3* (scenario 2) actually yielded a higher production rate even though it resulted in a lower gas lift supply pressure than scenario 3 at wellpads A4* and A5*. This is likely because setting a booster compressor upstream of A4* (scenario 3) only boosted the pressure for about 30 active wells. Whereas, setting a booster compressor upstream of A3* (scenario 2) actually helped to boost the gas lift supply pressure for up to 77 active wells. Thus, production from scenario 2 was higher likely because it benefited substantially more wells.

Table 2: Compiled Simulation Results

	Scenario 1 - Base Case	Scenario 2 - Compressor Upstream of A3*	Scenario 3 - Compressor Upstream of A4*	Scenario 4 - Shut-in Less Competitive Gaslift Wells
Oil (STB/d)	37090	37582	37163	37452
Δ Oil from Base Case (STB/d)	**0**	**492**	**73**	**362**
Water (STB/d)	103129	104260	103241	96733
Gas (MMscf/d)	88.128	88.364	88.136	87.33
A1 GL Press (psi)	2006	2006	2006	2008
A2 GL Press (psi)	1684	1892	1684	1729
A2 EXP GL Press (psi)	1690	1897	1690	1734
A3 GL Press (psi)	1836	2036	1836	1858
A4 GL Press (psi)	1642	1852	2022	1696
A5 GL Press (psi)	1638	1848	2018	1692
GL Used (MMscf/d)	439	439	439	428

At first glance, one might say the scenario that yielded the highest production of oil would be the most sensible option to pursue. However, there are several factors other than oil production that need to be considered in a potential investment decision. Although the installation of a booster compressor upstream of Wellpad A3* would boost production by 492 bopd, the substantial costs, safety risks, and time it would take to design, implement, and operate an additional compressor would need to be analyzed to determine the wholistic benefit of this option. This type of analysis alone would likely take at least three to six months to build a proper case.

Table 3 shows a hypothetical economic analysis of investing in an extra compressor versus shutting in the less competitive gas lift wells. Assuming a discount rate of 5% and an oil price of $50 per barrel for the next ten years, shutting in wells resulted in a much higher net present value of $46 million. Shutting in wells allowed for an instantaneous gain in production with no investment. It was assumed that an extra compressor would cost a rough estimate of $30 million and it would take three years to build and complete; strongly diminishing the value of the option.

Table 3: Hypothetical economic analysis of an extra compressor vs shutting in wells.

Invest in Extra Compressor				**Shut-in Wells**		
Disc Rate	0.05			**Disc Rate**	0.05	
Year	**Production**	**Cash flow**		**Year**	**Production**	**Cashflow**
0	0	-20000000		0	362	6606500
1	0	-5000000		1	347.5	6342240
2	0	-5000000		2	333.6	6088550.4
3	492.0	8979000		3	320.3	5845008.38
4	472.3	8619840		4	307.5	5611208.05
5	453.4	8275046.4		5	295.2	5386759.73
6	435.3	7944044.544		6	283.4	5171289.34
7	417.9	7626282.762		7	272.0	4964437.76
8	401.2	7321231.452		8	261.1	4765860.25
9	385.1	7028382.194		9	250.7	4575225.84
10	369.7	6747246.906		10	240.7	4392216.81
	NPV	**$16,200,504**			**NPV**	**$46,013,148**

Therefore, scenario 4 is the better option to pursue because all that needs to happen to realize the benefit is to shut-in five uncompetitive wells with no investment necessary. Although shutting in five wells shut-in about 227 bopd of production, the total gain resulted in an increase of ~589 bopd gross or ~362 bopd net. The increase in production was largely due to the boost in gas lift supply pressure by reducing the amount of uncompetitive gas lift users from the gas lift distribution network.

Another concept to consider is the reduction of backpressure in the production system due to shutting in the five producing wells. Since all the wells on the West End are constrained by a single large diameter flowline, removing less competitive wells will, in theory, make additional room for more competitive wells by reducing the overall backpressure in the large diameter flowline. A reduction of ~3 psi was realized in the model after shutting in the five wells in scenario 4. This reduction in pressure cascades all the way back to the individual wells which will slightly decrease the well head pressure for each well. Reducing the well head pressure on a well increases the downhole drawdown, usually resulting in an increase in production, depending on the wells productivity index.

Although the net gain of production by shutting in wells is 130 bopd less than adding a compressor upstream of Wellpad A3*, implementing scenario 4 is the realistic and optimal choice. The additional 130 bopd would not justify the extensive time, costs, and risks of adding a new compressor to the surface infrastructure. Also, since shutting in wells is operationally easy to implement, if it doesn't work, the wells can always be brought back online again.

7.0 Conclusion & Recommendation

A West End gas lift and production model was built to capture the effects on production due to low and fluctuating gas lift supply pressures. The models were matched to actual historical production with a small percentage of error in order to ensure that the output of the model closely represented reality within an allowable tolerance. The models were used to analyze four separate scenarios to determine which approach would be the most optimal and beneficial. Not only to maximize production, but to realistically consider other variables such as time, cost, and risk. It was found that scenario 4, where shutting in wells to boost gas lift supply pressure and reduce the backpressure in the constrained large diameter flowline would be the best scenario to implement due to the non-existent investment requirements and the ability to reverse the actions if it was found to hinder production instead. Further improvements to the model well enable it to simulate a little closer to reality and capture the physics involved with the dynamic nature of a gas lift system. These models have the capability to accurately simulate the West End production system and allow for predictive and optimization studies to further improve field production.

Although there was a small percentage of error in the model match, there is still room to improve the models. For example, the static nature of the model causes the differential pressure across the gas lift flow control valves to remain constant once it is used as an input. Any changes to the gas lift supply pressure or gas lift rates that the model calculates does not change the differential pressure across the flow control valves. In reality, the differential pressure would fluctuate with changes to the system. The way the flow control valves operated in the model also did not reflect reality quite well as valves with high amounts of differential pressure would see drastically lower casing pressures than reality.

Another issue was the differential pressure across the injecting gas lift valve. Normally, the upstream casing pressure of a gas lifted valve must be much greater than the downhole tubing pressure. The large amount of differential pressure enables a steady flow of gas across the gas lift valves. In Prudhoe Bay, the majority of the gas lifted wells have been designed to withstand differential pressure fluctuations greater than 200 psi and still lift from its deepest valve. However, the model calculates that a drop of 200 psi in supply pressure would no longer allow the well to lift from its deepest gas lift valve. The model would then move the injection point to the next shallower valve; inaccurately representing the well's behavior.

These two issues can be addressed by providing even more details into the flow control valves and well gas lift designs for the model. Flow rate vs differential pressure curves can be generated and incorporated for the flow control valves. Also, detailed gas lift valve sizing and spacing can be added in the model for each individual well for a more realistic representation on gas lift well performance.

A deeper analysis could also be made about how backpressure affects the constrained production system. It would be intriguing to see if production can be further increased by reducing the backpressure. However, since the West End's large diameter flowline is constrained on velocity and not pressure, the increase in production could likely cause a velocity limit excursion. Further analysis with the model would be able to determine the answer.

Nomenclature

BLPD – Barrels of Liquid per Day

BOPD – Barrels of Oil per Day

BWPD – Barrels of Water per Day

EWE – Eileen West End

FAC1* – Facility 1*

FAC2* – Facility 2*

FCV – Flow Control Valves

Ft/s – Feet per Second

GL – Gas Lift

GLV – Gas Lift Valves

GOR – Gas to Oil Ratio

HP – High Pressure

ID – Inner Diameter

IPR – Inflow Performance Relationship

IPSM – Integrated Production System Model

LDF – Large Diameter Flowline

MMscf/d – Million Standard Cubic Feet per Day

OGLV – Orifice Gas Lift Valve

Psi – Pounds per Square Inch

Pwf – Bottomhole Flowing Pressure

STB – Stock Tank Barrel

TGOR – Total Gas to Oil Ratio

Tscf – Trillion Standard Cubic Feet

TxIA – Tubing by Inner Annulus (communication)

NPV – Net Present Value

VLP – Vertical Lift Performance

WC – Watercut

WHP – Well Head Pressure

WHT – Well Head Temperature

WOA – West Operating Area

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